

ART OF THE SELF-DEAL:

HOW REGULATORY FAILURE LETS GAS PIPELINE
COMPANIES FABRICATE NEED AND FLEECE RATEPAYERS



This report was researched and written by Lorne Stockman and Kelly Trout of Oil Change International with contributions from Thomas Hadwin. It was copy edited by Emily Sproul.

The authors are grateful for feedback from the following reviewers: Alex Doukas and Janet Redman of Oil Change International, Tyson Slocum of Public Citizen, Joe Daniel, Cara Bottorff, and Deb Self of the Sierra Club and Amy Mall of the Natural Resources Defense Council.

Design: paul@hellopaul.com

September 2017

Published by Oil Change International in collaboration with Public Citizen and the Sierra Club.

Oil Change International is a research, communications, and advocacy organization focused on exposing the true costs of fossil fuels and facilitating the coming transition towards clean energy. For more information, visit www.priceofoil.org.

Public Citizen is a progressive consumer rights advocacy group and think tank that has been the people's lobbyist on issues including global trade, energy and corporate accountability for more than 45 years. For more information, visit <https://www.citizen.org>.

The Sierra Club is America's largest and most influential grassroots environmental organization, with more than 3 million members and supporters. In addition to helping people from all backgrounds explore nature and our outdoor heritage, the Sierra Club works to promote clean energy, safeguard the health of our communities, protect wildlife, and preserve our remaining wild places through grassroots activism, public education, lobbying, and legal action. For more information, visit www.sierraclub.org.

CONTENTS

GLOSSARY	2
EXECUTIVE SUMMARY	5
1. GAS AND PIPELINES IN THE APPALACHIAN BASIN	8
First Comes the Gas...	8
...Then Come the Pipelines	9
The Next Wave: Greenfield Interstate Gas Pipelines	12
2. HOW RATEPAYERS PAY FOR PIPELINES	14
FERC Fails to Assess Real Market Demand for New Pipelines	15
Ratepayers Bear the Risk and the Costs of Pipelines	18
FERC Rate Setting Distorts Pipeline Investment Decisions	20
CASE STUDIES	22
Atlantic Coast Pipeline	22
Mountain Valley Pipeline	24
PennEast Pipeline	25
NEXUS Pipeline	26
3. SHIFTING ENERGY TRENDS: DECLINING DEMAND AND CLEAN TECH MAKE GAS LOCK-IN A RISKY DEAL FOR RATEPAYERS	28
U.S. Energy Demand at a Crossroads	28
Forecasts for Gas Power Demand are Highly Uncertain	29
Clean Energy is Lower Risk for Ratepayers	31
Other Sources of Gas Demand are Vulnerable	31
RECOMMENDATIONS	32
Protecting Ratepayers Requires Due Diligence in Assessing Pipeline Need	32
REFERENCES	33

GLOSSARY

Affiliated Contract: A contract struck between two branches of the same company. This could include a parent company and a subsidiary it controls, or two subsidiaries of the same parent company.

Appalachian Basin: In this report, this refers to the U.S. gas production region that includes the Marcellus Shale, which lies largely below parts of Pennsylvania and West Virginia, and the Utica Shale, which lies largely below Ohio. Figures for Appalachian Basin gas production include all natural gas production in the three states.

Capacity Factor: The ratio of the electrical energy produced by a generating unit over a period of time compared to the maximum electrical energy that could have been produced by the unit during the same period.

Captive Customers: Customers of a utility service who do not have the ability to switch to another provider. This could include ratepayers of a regulated utility monopoly or shippers locked into service on an existing pipeline.

Certificate of Public Convenience and Necessity: A certificate issued by a regulatory body that authorizes the recipient to construct and operate a pipeline or other type of facility. The Natural Gas Act grants the Federal Energy Regulatory Commission authority to grant or deny such certificates for interstate gas pipelines. This certification gives pipeline companies the power to exercise eminent domain.

Depreciation Rate: The rate at which an asset decreases in value over the course of its estimated useful operating life.

Dispatching: In the context of power generation, this refers to the assignment of load to specific generating stations and other sources of supply. Typically, plants with the lowest variable operating costs are dispatched first, and plants with higher variable operating costs are brought on line sequentially as electricity demand increases.

Firm Service Agreement; Take-or-Pay Contract: A contract struck between the pipeline owner and a company committing to pay for a specified amount of daily capacity on the pipeline. The company reserving space on the pipeline can access the pipeline at all times at a predictable price, while the pipeline owner is guaranteed payment for the agreed amount of capacity whether or not it is used.

Fuel Surcharge: A fee added to ratepayers' utility bills that is additional to the base rate charged for utility service. Utilities apply to state regulators to approve fuel surcharges in order to recover the costs of contracts for both pipeline service and gas.

Greenfield Project: A project constructed through land that has never been used for similar purposes before, as opposed to a project that expands or upgrades an existing pipeline corridor.

Precedent Agreement: A type of firm service agreement used by pipeline developers to underwrite the upfront costs of building a pipeline. In the project planning stage, investors seek commitments from shippers to reserve firm service on a pipeline for the first 10 to 20 years of the project, which ensures the return of a significant proportion of the capital invested.

Rate of Return; Return on Equity: The rate of return is the ratio of total profits earned compared to the capital or assets. A pipeline's return on equity is the net profits earned compared to the value of the net assets.

Regulated Monopoly: A private or publicly owned utility that is guaranteed to be the sole service provider within a designated area while having its rates and resource planning overseen by regulators.

Self-dealing: For the purposes of this report, we refer to a financial arrangement involving affiliated companies that privileges the financial interests of shareholders over the best interests of clients or captive customers. A utility contracting for firm service from a pipeline owned by an affiliated holding company is essentially serving two different masters – its ratepayers and the shareholders of the parent company. This sets up a conflict of interest that enables potential abuse and risk-shifting.

Shipper: A company that contracts with a pipeline to transport gas through it.

Tariff: A tariff includes the rate schedule, terms, and conditions involved in paying for transportation service through a pipeline. FERC regulates the tariff that pipeline owners can charge shippers.



Abbreviations used in this report:

ACP	Atlantic Coast Pipeline
Bcf/d	Billion cubic feet per day
BNEF	Bloomberg New Energy Finance
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Billion Watts (a measure of power)
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
Mmcfd	Million cubic feet per day
MVP	Mountain Valley Pipeline
MW	Million Watts
NEO	New Energy Outlook (published by Bloomberg New Energy Finance)
NGA	Natural Gas Act
PSC	Public Service Commission
PV	Photovoltaics
ROE	Return on Equity



EXECUTIVE SUMMARY

This report finds that regulators are asleep at the wheel when it comes to assessing whether new gas pipelines are in consumers' best interest. In this vacuum of oversight, corporations could shunt the financial costs and risks of a new wave of gas pipelines on to utility ratepayers.

To safeguard consumers from unfair and unnecessary costs, the Federal Energy Regulatory Commission (FERC) should immediately initiate a review of long-term market demand for gas and of the Commission's granting of excessive rates of return on equity for pipelines. State Public Service Commissions (PSCs) should assert their authority to review contracts between the utilities they regulate and the proposed gas pipelines in which affiliates of these same companies are investing. FERC should halt all permitting of interstate gas pipelines in the meantime. Here is why.

The U.S. is in the middle of an unprecedented gas pipeline building spree. Traditional pipeline builders are facing competition from new entrants into the pipeline industry. Utility holding companies like Dominion Energy, Duke Energy, and DTE, and gas producers like EQT, are launching their own projects to cash in on the high returns associated with pipeline development. But are these projects actually needed?

Projects already approved or pending before federal regulators in 2017 alone could add over 2,400 new miles of pipeline

across and out of the Appalachian Basin.¹ If fully realized, new projects slated to come online by the end of 2018 could increase the flow of gas from fracking operations in the Marcellus and Utica shale formations by over 71 percent, adding 16 billion cubic feet per day (Bcf/d) of additional pipeline capacity.² Even more are slated to follow.

The ambitious scale of this pipeline build-out should trigger greater regulatory scrutiny than ever before – not only of the risks to the environment, climate,³ and landowners through use of eminent domain, but also of the risks to U.S. consumers. Consumer risks have received comparatively little attention to date.

As they race to construct new projects, pipeline developers are turning to self-serving financial arrangements that shift the costs and risks of paying for them on to gas and electric utility customers, often those of an affiliated company. **Absent effective oversight, ratepayers could end up shouldering long-term costs for pipeline capacity they don't need, while losing out on opportunities to take advantage of increasingly cheaper, cleaner choices.**

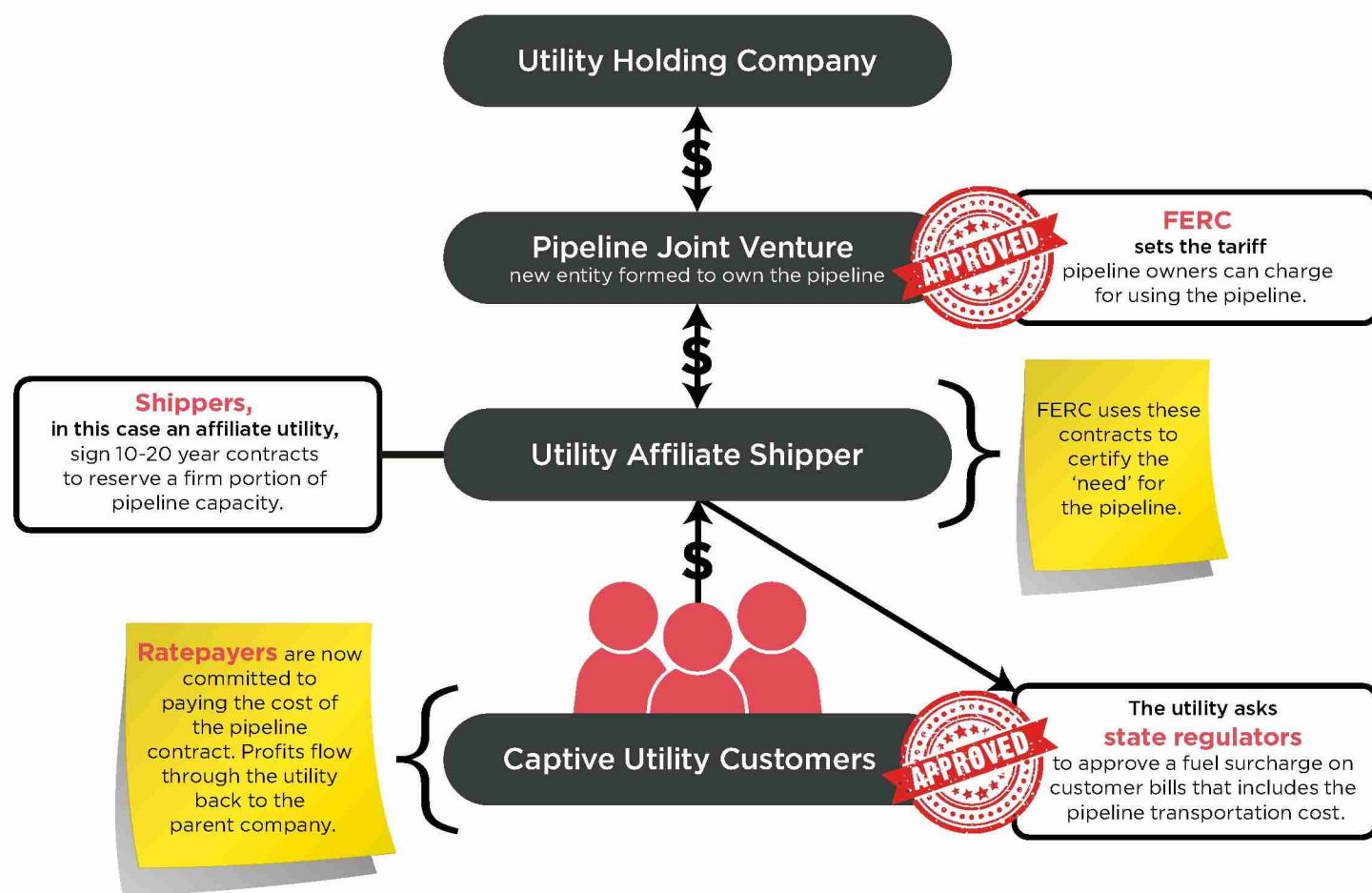
Unfortunately, FERC, which is responsible for permitting interstate gas pipelines, is failing to protect consumers. FERC is conducting virtually no independent assessment of a fundamental question: **Does genuine, long-term demand exist for this rash of new pipelines – infrastructure designed to last 40 years or more?**

This core question of need is one FERC must start answering *before* ratepayers see the costs of new infrastructure passed through to their gas or electric utility bills. Greater scrutiny is required now more than ever due to three key factors that are heightening risks to ratepayers, and which are examined closely in this report:

- 1) **Corporate self-dealing is increasing the likelihood that ratepayers, not shareholders, bear the financial risks of investing in unneeded infrastructure:** Many of the pipeline applications before FERC involve self-dealing contracts between pipeline developers and their affiliates. An affiliate of the pipeline developer signs a long-term contract to reserve capacity on the pipeline. The developer then presents this contract, called a precedent agreement, to FERC as proof of market need. When the affiliate is a regulated gas or electric utility, it can pass the costs of this transportation agreement through to captive ratepayers (See Figure ES-1). If state regulators approve this cost (which is typical), ratepayer money is then guaranteed to flow through the utility back to the arm of the company that owns the pipeline, even if the additional gas demand does not fully materialize.
- 2) **High rates of return may be incentivizing unnecessary pipelines:** FERC allows a return on equity of 14 percent for new interstate gas pipelines.^a This rate was first set in 1997 when interest rates were

^a In many cases, the full rate of return negotiated between pipeline companies and FERC is 15 percent or more. Return on equity (ROE) is commonly referred to in FERC proceedings, so we used it here for consistency. But ROE only represents a portion of the full return on these projects as equity only makes up a portion of the capital used. A 15 percent return on any investment in today's low-interest environment is generous by any measure and constitutes a strong incentive for pipeline development.

Figure ES-1: How Self-Dealing Can Shift Pipeline Costs On To Utility Ratepayers



double today's average.⁴ It has not been revised since. It is also about 40 percent higher than what companies typically receive for other types of utility investments. This comparatively high return provides an incentive for utility holding companies and gas producers to enter into the pipeline business, especially as utilities face stagnant or declining revenues from electricity sales. It also incentivizes the building of new infrastructure over the efficient use of existing pipelines, which have been paid off by previous ratepayers.

3) **In today's dynamic energy landscape, the demand for gas over the next 20 years and beyond is highly uncertain.** For the first time in U.S. history, power demand is decoupling from economic growth. Technological innovation is improving the efficiency with which we use energy and providing a wider range of low-cost energy sources such as renewable energy and storage. At present, FERC is taking on faith the primary justification for building

more pipelines presented by pipeline developers: that demand will grow to supply new gas-fired power plants. Given the rapid pace of technological change, these assumptions are increasingly tenuous and deserve much greater scrutiny.

By failing to assess the long-term market demand for new pipelines, FERC risks certifying a dramatically expanded pipeline system with capacity to supply far more gas than end-users actually need. When these projects involve self-dealing financial arrangements with utilities that have captive customers, it is ratepayers, not shareholders, who could shoulder the unnecessary costs. FERC's responsibility to ensure "just and reasonable"⁵ rates for consumers is compromised by this lack of diligence.

As former FERC commissioner Norman Bay warned earlier this year, an overbuilt pipeline system could raise costs for ratepayers relying on existing pipelines too. "If a new pipeline takes customers

from a legacy system," Bay cautioned, "the remaining captive customers on the system may pay higher rates."⁶

Ultimately, FERC has a core mandate under federal law to determine whether proposed interstate gas pipelines serve the "present or future public convenience and necessity," and to deny applications that do not.¹¹ At present, FERC bases its determination of 'necessity' on little more than the precedent agreements signed between pipeline developers and shippers. However, when those contracts are signed between arms of the same company, as they increasingly are today, they provide no concrete evidence of actual market demand. FERC's 1999 Statement of Policy addressed this issue, establishing wider parameters for determining need, but FERC is not fully implementing it.¹²

Amid an unprecedented rush of new pipeline proposals, and the rapid growth of cost-competitive energy alternatives, FERC must overhaul its pipeline permitting process to protect the interests of U.S.

CASE STUDIES

This report provides case studies of four pipeline proposals either pending or recently permitted by FERC – **Atlantic Coast Pipeline, Mountain Valley Pipeline, PennEast Pipeline, and NEXUS Pipeline** – that illustrate consumer risks. Each of these projects involves significant levels of self-dealing between affiliated companies, and each also involves captive utility customers. Risks FERC has failed to evaluate include:

- The **Atlantic Coast Pipeline**, proposed by utility holding companies Dominion Energy, Duke Energy, and Southern Company, could be 3.5 times more expensive for Dominion utility customers in Virginia compared to sourcing gas from an existing pipeline system.^b
- In the case of the **Mountain Valley Pipeline**, 100 percent of the pipeline's capacity is reserved by affiliates of the pipeline's owners. The pipeline companies' case for need is built entirely

upon affiliate contracts that suggest self-dealing.⁷ Yet FERC has not questioned the need at all. The New York utility arm of Con Edison (Con Ed) could end up hitching its customers to over \$60 million per year in largely excess costs, while its transmission affiliate recoups profit as part-owner of the pipeline.⁸

- The New Jersey Rate Counsel has warned FERC that the **PennEast Pipeline** “appears to be driven more by the search for higher returns on investment than any actual deficiency in gas supply or pipeline capacity to transport it.”⁹
- Only 59 percent of the **NEXUS Pipeline's** overall capacity is reserved. Michigan's attorney general has questioned whether the gas and electric utility affiliates of DTE – a half-owner of the project – properly considered alternatives before signing a precedent agreement committing to pay for part of the pipeline's capacity.¹⁰

consumers from the profit motives of pipeline developers.

FERC should pause all permitting of new pipelines unless and until it implements necessary reforms. Specifically, FERC must:

- **Stop using precedent agreements as evidence of the ‘public convenience and necessity’ of new pipelines, especially when contracts are between affiliated companies and involve captive utility customers.** In other contexts, FERC has observed the need to protect against affiliate abuse and self-dealing.¹³ To protect customers against risk-shifting, FERC should update its policies so that affiliate precedent agreements are no longer considered acceptable proof of the need for new pipelines.
- **Thoroughly and independently assess the long-term market need for proposed pipelines – and deny permits when need is not clearly established.** FERC should analyze long-term regional demand, the efficiency and utilization of existing pipelines, cost-effective alternatives like clean energy and storage, and a broad range of factors to determine public need. This assessment would be similar in some respects to the regional planning conducted for electricity transmission.

- **The independent assessment should require an evidentiary process** – involving hearings that allow commissioners and public advocates to cross-examine industry witnesses. This is the best way to ensure a full and fair assessment of need is carried out. FERC should establish the Office of Public Participation to facilitate the engagement of impacted communities and consumer advocates in the process.¹⁴
- **Reduce the return on equity authorized for new pipeline projects to reflect current market conditions.** The 14 percent return on equity has not been reviewed by FERC in 20 years, despite the current era of low interest rates. FERC should revise this rate downward to conform with current market and investment conditions and with typical rates for comparable utility investments, including clean energy such as energy efficiency and renewable energy. Otherwise, the agency itself may be inappropriately shaping energy markets, luring companies into the pipeline business and incentivizing the construction of unnecessary pipelines at the expense of ratepayers.

State PSCs also have a crucial role to play, given that their job is to protect ratepayers from unreasonable costs. When FERC fails to properly evaluate the need for new pipelines, federal regulators make it harder for state regulators to do this job. PSCs are

forced to make decisions about rates based on pipeline infrastructure already deemed ‘necessary’ by FERC, and on contracts that state utilities have already signed. **To protect ratepayers under their jurisdiction, state PSCs should take the following action:**

- File protests in relevant FERC pipeline dockets immediately, demanding that FERC fully evaluate the market need for any new pipeline that would impact their state's ratepayers.
- In cases where a utility has entered into a contract to buy gas from an affiliated pipeline developer, invoke their authority to review the prudence of that affiliate contract. Affiliate review statutes exist in many states to protect consumers from self-dealing transactions that do not serve ratepayers' interests.
- Apply heightened scrutiny to determine whether rate hikes related to new pipeline transportation costs are just and reasonable, especially when affiliate self-dealing is involved.

Ultimately, when regulators fail to assess whether new pipelines are actually needed, they hand pipeline companies an opportunity to gouge U.S. consumers. Given the associated environmental risks and property rights abuses, and the gathering pace of the clean energy transition, such a failure in regulatory oversight is unacceptable.

^b See Table 1 in the Atlantic Coast Pipeline case study.

1. GAS AND PIPELINES IN THE APPALACHIAN BASIN

The ongoing race to expand gas pipeline capacity from the Appalachian Basin is occurring within a particular context that may not be obvious at first glance. It is not driven by dramatically rising demand for new supplies of gas either within the region or nationally. Rather, it is a profit-driven race to fully exploit gas to which producers have already acquired the rights. It is enabled by new drilling methods and poor regulatory oversight that render the gas both abundant and relatively cheap to produce.¹⁵

This context, together with the analysis in Section 3 that discusses declining prospects for gas demand, clearly indicates that the burgeoning pipeline buildout is a supply-led, rather than a demand-led activity. At present, Appalachian Basin gas is primarily replacing supplies from other parts of the continent that are either in decline,

or simply being exported to international markets.

As America becomes more energy efficient and has greater energy choices provided by renewable energy and clean technology, gas-fired power is in direct competition with these clean technologies for a share of a shrinking market.

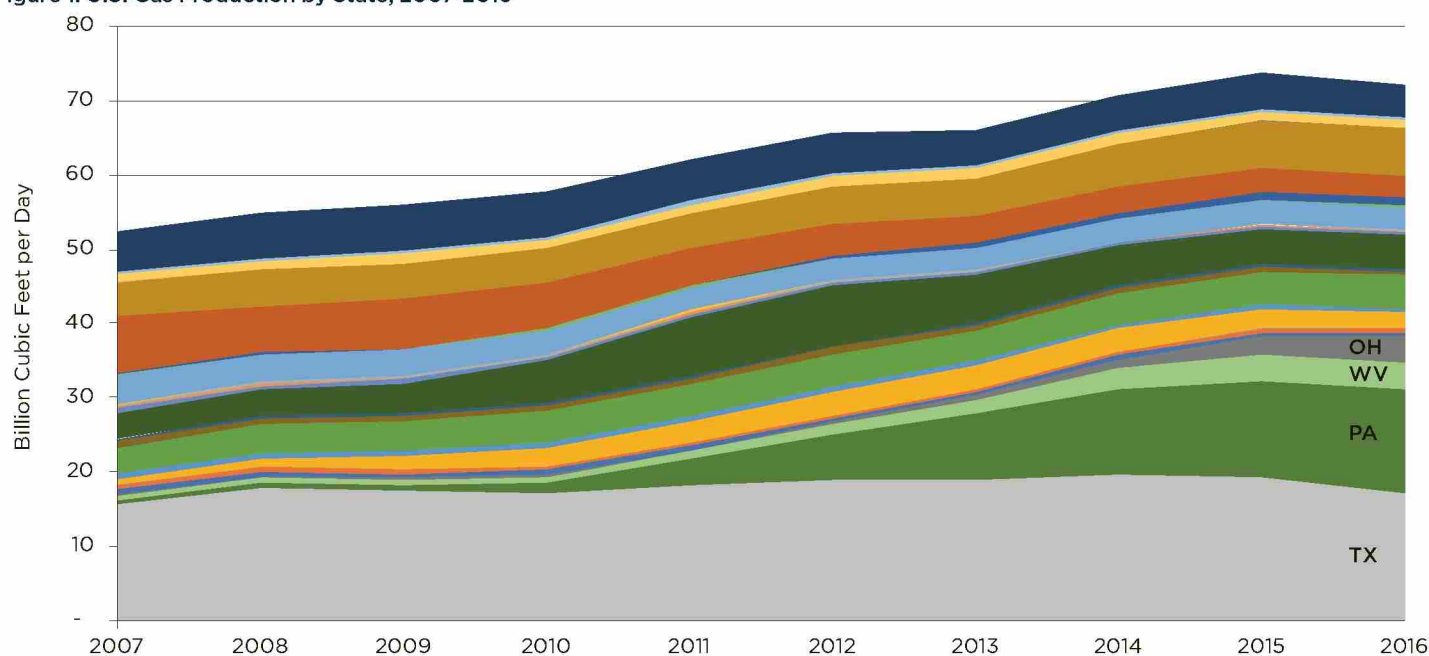
As a new wave of pipelines looms, gas producers and pipeline developers are increasingly seeking to push long-term gas transportation contract costs on to ratepayers as a mechanism by which to lock in market share – and reliable profits – whether or not customers ultimately need all of the gas these pipelines promise to deliver. This dynamic requires greater scrutiny and diligence from regulators than ever before.

FIRST COMES THE GAS...

Since around 2010, a substantial geographical shift in U.S. gas production has taken place. Horizontal drilling coupled with advanced methods of hydraulic fracturing (fracking) was first deployed at a commercial scale in the Barnett Shale in northern Texas. This drilling technique has enabled access to vast reserves of gas lying below parts of Pennsylvania and West Virginia, known as the Marcellus Shale, as well as another formation primarily in Ohio, known as the Utica Shale. We refer collectively to this gas production region as the Appalachian Basin.

In less than a decade, Pennsylvania has become a state with a gas production rate second only to Texas, emerging from a position of obscurity prior to 2010 (See Figure 1).

Figure 1: U.S. Gas Production by State, 2007-2016



Source: Rystad Energy AS (August 2017)

While growth in Appalachian Basin gas production has already been aggressive, industry projections indicate that production could roughly double from 2016 levels over the coming decade¹⁶ – but only if pipeline capacity grows in line with drilling and fracking activity and if markets support such rapid growth. In other words, this growth is not inevitable.

If this rapid growth does occur, Pennsylvania could overtake Texas as the largest gas producer in the United States, and West Virginia and Ohio could overtake other states to become the third and fourth gas producers respectively (see Figure 2).

However, even as Appalachian Basin gas production could increase over the next decade, total U.S. gas production is likely to start declining in the early 2020s, perhaps just five to seven years from now (see Figure 2). While this would suggest that Appalachian Basin producers are in a strong position to capture market share, interrelated market and policy shifts could create headwinds. As discussed in Section 3, rapid technological shifts make the future of U.S. and global gas

demand increasingly uncertain. There are also significant climate risks associated with producing and consuming gas at the rate implied in this projection.^{17,18} If power demand continues to flatten and decrease, and if necessary regulatory and legislative action to curb climate change is implemented, the pipelines being proposed now to facilitate production growth in the Appalachian Basin could be significantly underutilized.

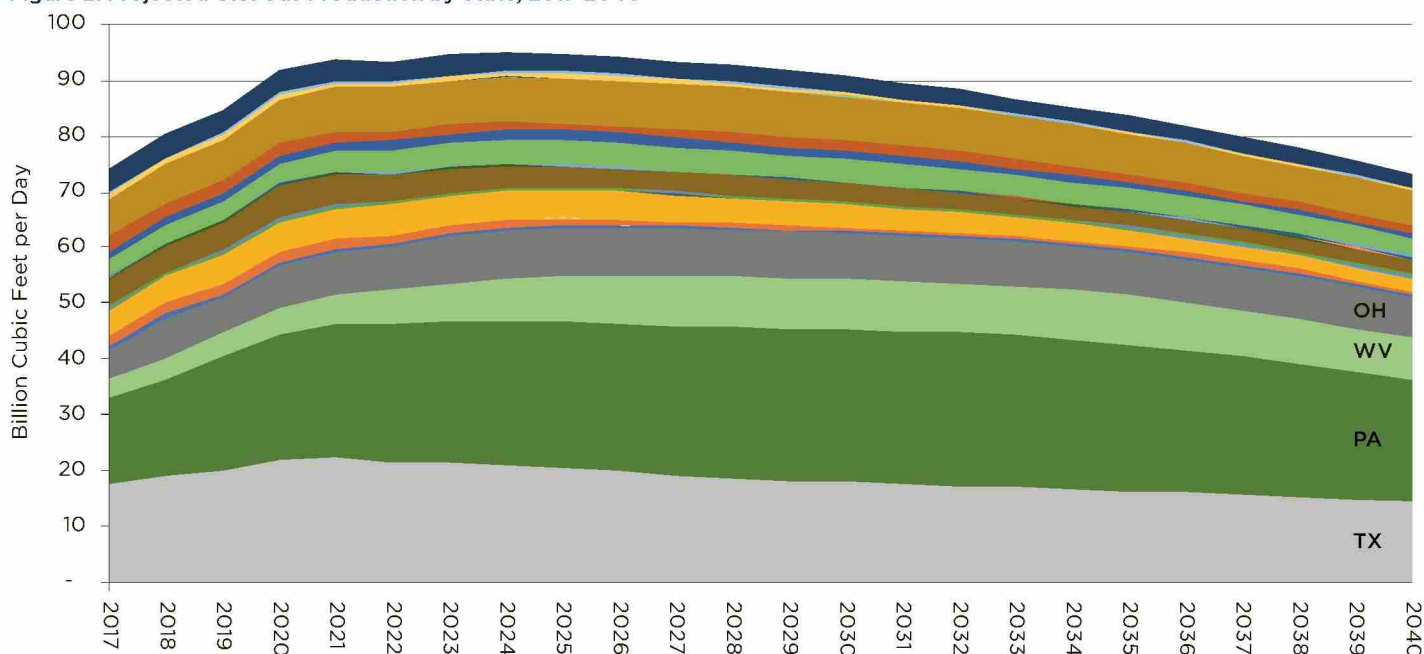
...THEN COME THE PIPELINES

Pipeline construction activity has been intense in the Appalachian region for some time. This has developed at several levels. At a local level, thousands of miles of gathering lines have been laid to gather gas from thousands of well sites and channel it to processing plants. Transmission lines then deliver it on to storage facilities, power plants, industrial customers, or larger interstate transmission lines. At the interstate transmission level, which is the level examined in this report, the bulk of capacity expansions to date have focused on connecting, redirecting, and expanding the existing network of pipelines.

Much of the legacy interstate transmission network is decades old and was built primarily to transport gas from the Gulf Coast region to the northeast. Today, these legacy pipelines carry gas from the Appalachian Basin not only to the northeast, but also back south to the Gulf Coast, where much of it will find its way to export markets via new liquefied natural gas (LNG) export terminals.¹⁹ One part of the legacy network, Columbia Gas Transmission, which is now owned by TransCanada, is currently undergoing expansion and redirection to carry Appalachian gas to the Gulf Coast. This involves some new pipeline and compressor stations as part of the Leach Xpress and Rayne Xpress projects.

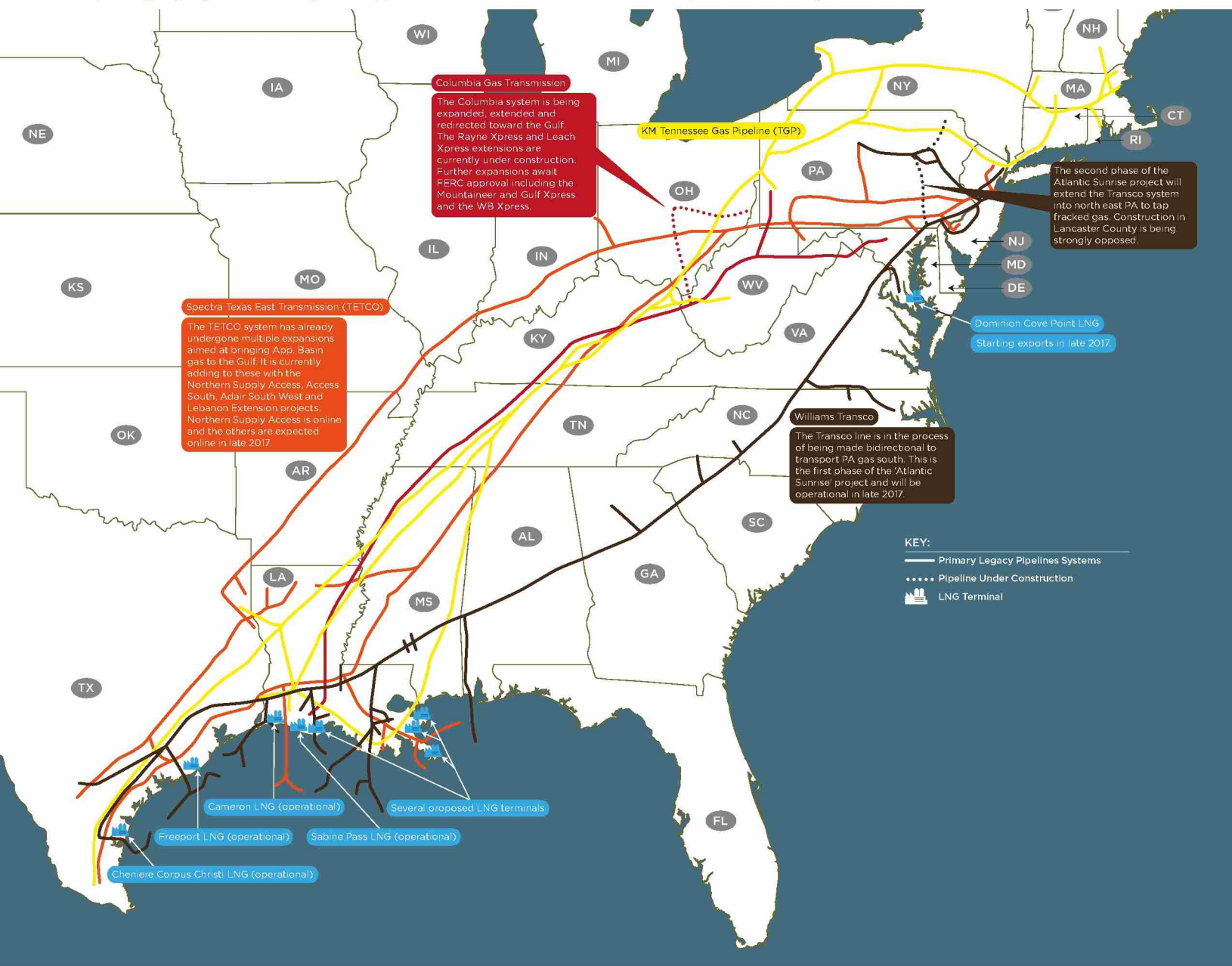
The exception to this wave of north-south expansion of legacy pipeline networks is the Rockies Express Line, known as REX. REX was built in 2006 to transport gas from Wyoming and Colorado through the Midwest to Ohio. This pipeline has now been made bidirectional and connected to gas sources in Ohio, Pennsylvania, and West Virginia so that it carries gas from both the Rockies and the Appalachian Basin to Midwest markets.

Figure 2: Projected U.S. Gas Production by State, 2017-2040



Source: Rystad Energy AS (August 2017)

Map 1: Legacy Pipelines through the Appalachian Basin inc. extensions and expansions and key LNG terminals



Note: This map features major legacy pipeline projects that are key to gas production expansion in the Appalachian Basin and does not include all pipelines.

Map 2: Greenfield Pipelines



Note: This map focuses on those pipelines mentioned in this report and does not show all the pipelines proposed and under construction in the region. Many of these connect with legacy pipelines shown in Map 1.

IN 2016, FERC APPROVED OVER 17 BCF/D OF NEW GAS PIPELINE CAPACITY NATIONALLY, ENOUGH TO CARRY NEARLY A QUARTER OF U.S. GAS CONSUMPTION.

THE NEXT WAVE: GREENFIELD INTERSTATE GAS PIPELINES

Until recently, this replumbing of the regional gas pipeline network – focused on redirecting and expanding existing pipelines to carry more gas out of the Appalachian Basin – had roughly kept pace with the region's prolific gas production growth. However, as producers set their sights on potentially doubling production in the region, and seek new markets to match their expansion goals, established pipeline companies, as well as new entrants to the pipeline business like utility holding companies, are planning a raft of additional 'greenfield' projects that would carve new pipeline corridors across and out of the Appalachian Basin. One such project, the massive 3.25 Bcf/d Rover Pipeline, is already under construction.

In 2016, FERC approved over 17 Bcf/d of new gas pipeline capacity nationally,²⁰ enough to carry nearly a quarter of U.S. gas consumption.²¹ In 2017, FERC could approve over 2,400 miles of new pipeline out of the Appalachian Basin alone, including major projects already approved and those pending final review.²² Bloomberg estimates that, if fully realized, new projects slated to come online by the end of 2018 could increase the flow of gas from fracking operations in the Appalachian Basin by over 71 percent, adding 16 Bcf/d of additional pipeline capacity.²³

The ambitious scale of these projects calls into question not only their vast environmental footprint, but fundamentally whether they are needed. Are they meeting genuine demand for gas, or serving the gas pipeline industry's desire for profits? Absent

effective regulatory oversight, corporations could end up locking ratepayers into paying a premium for pipelines that do not serve their best interest.

Among several projects proceeding through the FERC regulatory process are four that are owned or partially owned by companies whose primary business is not pipelines: the Atlantic Coast, Mountain Valley, PennEast, and NEXUS projects.^c While these four projects are not alone in raising questions of ratepayer risk, they are particularly good examples of the concerns FERC is failing to address. Each project will be discussed in brief case studies in Section 2.

c NEXUS obtained a Certificate on August 25, 2017 as this report was going to press.

Drilling rig in Washington County, Pennsylvania operated by Range Resources.





2. HOW RATEPAYERS PAY FOR PIPELINES

Ratepayers may bear the cost of new pipeline infrastructure through fuel surcharges that regulated utilities directly charge their customers. A utility's cost of using a pipeline is bundled into the fuel surcharge together with the costs of the gas.

State regulated utility monopolies are especially well positioned to pass the costs of pipeline investments through to captive customers. The fuel surcharge is approved by state regulators that have the power to block the inclusion of expensive or unnecessary infrastructure costs from being passed through to ratepayers. However, in practice interstate gas transmission infrastructure that is certified as necessary by the Federal Energy Regulatory Commission is rarely challenged (see Box 2).

The utility's cost for gas itself will fluctuate with the market. However, the cost of transporting gas via a particular pipeline is usually locked in for 10 to 20 years, regardless of how much gas is transported.

This is because that cost generally comes in the form of a long-term 'firm transportation' contract that reserves capacity on the pipeline whether or not it is used. Therefore, in signing such a contract, the utility is committing its captive customers to paying for the capacity reservation for the entire period of the contract.

There are three reasons why this process requires far greater scrutiny today than ever before:

- 1) **Corporate self-dealing is increasing the likelihood that ratepayers, not shareholders, bear the financial risks of investing in unneeded infrastructure:** Many of the pipeline applications before FERC involve self-dealing contracts between pipeline developers and their affiliates. An affiliate of the pipeline developer signs a long-term contract to reserve capacity on the pipeline. The developer then presents this contract, called a precedent agreement, to FERC as proof of market need. When the

affiliate is a regulated gas or electric utility, it can pass the costs of this transportation agreement through to captive ratepayers (See Figure 4). If state regulators approve this cost (which is typical), ratepayer money is then guaranteed to flow through the utility back to the arm of the company that owns the pipeline, even if the additional gas demand does not fully materialize.

- 2) **High rates of return may be incentivizing unnecessary pipelines:** FERC allows a return on equity of 14 percent for new interstate gas pipelines.^d This rate was first set in 1997 when interest rates were double today's average.²⁴ It has not been revised since. It is also about 40 percent higher than what companies typically receive for other types of utility investments. This comparatively high return provides an incentive for utility holding companies and gas producers to enter into the pipeline business, especially as utilities face stagnant or declining revenues from electricity sales.

[R]ATEPAYER MONEY IS ... GUARANTEED TO FLOW THROUGH THE UTILITY BACK TO THE ARM OF THE COMPANY THAT OWNS THE PIPELINE, EVEN IF THE ADDITIONAL GAS DEMAND DOES NOT FULLY MATERIALIZE.

^d In many cases, the full rate of return negotiated between pipeline companies and FERC is 15 percent or more. Return on equity (ROE) is commonly referred to in FERC proceedings, so we used it here for consistency. But ROE only represents a portion of the full return on these projects as equity only makes up a portion of the capital used. A 15 percent return on any investment in today's low-interest environment is generous by any measure and constitutes a strong incentive for pipeline development.

BOX 1 - EMINENT DOMAIN FOR PRIVATE GAIN

Eminent domain is essentially the power of the government to take private property and convert it into public use.⁴⁶ The Fifth Amendment of the U.S. Constitution provides that government must pay just compensation for such use. Congress amended the Natural Gas Act in 1947, delegating the power of eminent domain to private, interstate gas pipelines to enable the transport of natural gas in interstate commerce.⁴⁷ However, the right of a private company to exercise eminent domain derives from the granting by FERC of a Certificate of Public Convenience and Necessity.

With the proliferation of pipelines in recent years, an increasing number of landowners are unwilling to bear the risks of gas

pipelines on their land. As a result, private corporations have increasingly exercised their power to seize land through eminent domain to construct pipelines.

On September 5, 2017, a group of landowners along the routes of both the Atlantic Coast and Mountain Valley pipelines in West Virginia, Virginia, and North Carolina filed suit against FERC, arguing that the eminent domain provisions of the Natural Gas Act as applied to both pipelines are unconstitutional.⁴⁸ A core argument in both suits is that the affiliated contracts presented in the certificate applications are an exercise of monopoly power and therefore contrary to the public interest.

It also incentivizes the building of new infrastructure over the efficient use of existing pipelines, which have been paid off by previous ratepayers.

3) In today's dynamic energy landscape, the demand for gas over the next 20 years and beyond is highly uncertain.

For the first time in U.S. history, power demand is decoupling from economic growth. Technological innovation is improving the efficiency with which we use energy and providing a wider range of low-cost energy sources such as renewable energy and storage. At present, FERC is taking on faith the primary justification for building more pipelines presented by pipeline developers: that demand will grow to supply new gas-fired power plants. Given the rapid pace of technological change, these assumptions are increasingly tenuous and deserve much greater scrutiny.

For these reasons, ratepayers would be better served by a thorough assessment of the long-term market for gas before being committed to paying the costs of a new pipeline. But so far, FERC has failed to conduct such an assessment for any of the projects it has permitted or is currently considering. While state regulators can review and amend retail rates and charges, the finding by FERC of "public convenience and necessity" places a burden on the state regulator to prove otherwise. This can lead to protracted legal and regulatory wrangling that is also not in the ratepayers' best interest when they could have been avoided.

The rest of this section explores these issues in more detail. We examine how FERC's current actions on gas pipeline permitting fail to assess genuine market need for a project, overlook significant self-dealing, incentivize new pipelines over efficient use of existing infrastructure, and dump the financial risk of new pipelines on to ratepayers. We illustrate these points with examples from four projects, three of which are awaiting FERC certification.

FERC FAILS TO ASSESS REAL MARKET DEMAND FOR NEW PIPELINES

FERC is authorized by the Natural Gas Act (NGA) to issue a certificate for the construction and operation of an interstate gas pipeline only when it "is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied."²⁵ The required permit to proceed with the construction and operation, or expansion of, interstate gas pipelines is called a Certificate of Public Convenience and Necessity.²⁶

Furthermore, the need for a project is central to the evaluation that the National Environmental Policy Act (NEPA) requires of a lead federal agency. Anything short of a thorough and rigorous evaluation of the need for a project and its possible alternatives in the project's Environmental Impact Statement (EIS) fails to meet the standards of federal law.

Despite these clear directives, the process by which FERC assesses "public convenience and necessity" is entirely superficial in practice. While the environmental impacts of hundreds of

miles of buried gas pipeline must by law be thoroughly assessed and accounted for, FERC has yet to determine a single pipeline's environmental impact to be prohibitive of permitting.

The bar appears to be set extremely low for demonstrating a market need for a project, which is the key factor weighed against the adverse effects of a project. In the only two cases where FERC has not approved a certificate for natural gas infrastructure, the project applicants failed to provide evidence of a single committed customer for either project.²⁷ One of these is reapplying, while the other has fallen by the wayside.

In practice, FERC's process for determining market need has rested entirely on the developer presenting shipper contracts, referred to as precedent agreements. The Commission has thus far applied no greater scrutiny to the assessment of market need even when those contracts are signed with companies owned by or affiliated with the pipeline developer applying for the certificate.

This is despite policy guidelines issued in 1999, in which the Commission expanded the scope of its assessment of need. The new guidelines stated:

Rather than relying only on one test for need, the Commission will consider all relevant factors reflecting on the need for the project. These might include, but would not be limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand

with the amount of capacity currently serving the market. The objective would be for the applicant to make a sufficient showing of the public benefits of its proposed project to outweigh any residual adverse effects.²⁸

In the same policy statement, the Commission further recognized that “[u]sing contracts as the primary indicator of market support for the proposed pipeline project also raises additional issues when the contracts are held by pipeline affiliates.”²⁹

In February 2017, outgoing FERC chairman Norman Bay pointed to the gap between current FERC policy and practice in assessing the need for new pipelines as a key issue to address, noting in his departing statement that:³⁰

[F]ocusing on precedent agreements may not take into account a variety of other considerations, including, among others: whether the capacity is needed to ensure deliverability

to new or existing natural gas-fired generators, whether there is a significant reliability or resiliency benefit; whether the additional capacity promotes competitive markets; whether the precedent agreements are largely signed by affiliates; or whether there is any concern that anticipated markets may fail to materialize.

Bay was acknowledging aspects of the evolving natural gas market that are becoming obvious to many in the industry, but to date have been completely ignored by FERC. In a recent article discussing the pending slate of interstate gas pipelines awaiting FERC approval, Rick Smead of RBN Energy noted that, “[t]hese days, with producer shippers being ferociously attentive to their operating expenses, with competitive power markets that don’t support generators paying for firm pipeline capacity and with pipeline concerns over the creditworthiness of some shippers, it is getting harder and harder to rope in that stable of foundation shippers that enables a pipeline to be built.”³¹

These issues and the pipeline sector’s solution, primarily signing up affiliated companies in self-dealing contracts, is something FERC is utterly failing to scrutinize.

The projects we highlight in this report all raise significant self-dealing concerns based on the extent of affiliate involvement in the precedent agreements presented as proof of market need. The percentage of capacity reserved by affiliates ranges from 100 percent to 17 percent in these four projects.^e Yet FERC has not questioned the market need for any of them. In the environmental impact statements drafted for each, FERC applies the same narrow parameters to navigate the issue.

First, FERC accepts on face value the purpose of the project as described by the companies proposing it. FERC offers either cursory analysis or none at all of the companies’ recurring claims that their proposed pipelines will increase access to “lower-priced”³² gas and/or meet “increased demand”³³ and “growing energy needs.”³⁴

^e The Mountain Valley Pipeline’s capacity is fully subscribed to by affiliated companies. Affiliate contracts account for 93 percent, 49 percent, and 17 percent of the current subscribed capacity of the Atlantic Coast Pipeline, PennEast Pipeline, and NEXUS Pipeline respectively. Of the latter three pipelines, none are fully subscribed to by shippers; therefore, the affiliate contract proportions compared to maximum possible pipeline capacity vary.



[A] PIPELINE OWNER'S CONTRACT TO SELL CAPACITY – EVEN WHEN PRIMARILY TO ITS OWN MARKETING SUBSIDIARY – HAS REMAINED SUFFICIENT PROOF OF MARKET DEMAND FOR FERC.

No attempt to compare projected demand for natural gas with the ability of existing pipelines to supply it is made. FERC generally cites the percentage of capacity booked by shippers as proof that a market for a project exists.

In issuing a Certificate Order approving the NEXUS pipeline, which has contracts to fill only 59 percent of the project's capacity, FERC acknowledged that there is "a significant portion of its capacity that remains unsubscribed."³⁵ In this case, FERC concludes the project will nonetheless "serve a demonstrated demand for natural gas" based on NEXUS's assertion that "many new gas-fired plants are planned" and based on FERC's determination that existing pipelines cannot provide the same volume of additional gas supply to the region.³⁶ FERC asserts the NEXUS project "is not intended to replace service on other pipelines,"³⁷ even though executives with DTE, half-owner of the project, have essentially acknowledged the opposite to their own investors.³⁸

In this case, FERC looks beyond contracts but does not provide any independent analysis to verify NEXUS's own claims as to the purpose of the project and whether long-term demand for gas warrants the additional supply. This is despite the fact that NEXUS serves the same markets as the under-construction Rover Pipeline and TransCanada's existing mainline in Canada.

After taking pipeline developers' stated purpose at face value, FERC's approach is to then define a viable alternative as something that delivers an equivalent amount of gas between roughly the same geographical points within a similar timeframe. This narrow definition precludes any consideration of whether a sustainable market for the additional gas to be delivered exists, or whether less environmentally impactful means of meeting energy needs would be a competitive alternative for ratepayers.

This line from FERC's final EIS on the PennEast pipeline is typical of how the agency pushes consideration of renewable energy or efficiency alternatives completely off the table: "[B]ecause the purpose of the Project is to transport natural gas, and the generation of electricity from renewable energy sources or the gains realized from increased energy efficiency and conservation are not transportation alternatives, they are not considered or evaluated further in this analysis."³⁹

Meanwhile, FERC rejects the alternative of 'no action,' or not building the pipeline, by again assuming shippers' precedent agreements equate to definitive market demand. For instance, in evaluating alternatives to the Mountain Valley Pipeline, FERC concludes, "[I]f the MVP is not authorized or not constructed, shippers may seek other means of transporting the

proposed volumes of natural gas ... which may result in equal or greater environmental impacts."⁴⁰ FERC does not consider any alternative means to meet energy need, such as energy efficiency, renewable energy or the capacity of existing pipelines to provide the same service.

Despite the stated recognition of a potential problem with affiliated contracts, a pipeline owner's contract to sell capacity – even when primarily to its own marketing subsidiary – has remained sufficient proof of market demand for FERC to issue a certificate to build and operate a pipeline.

This failure to carry out any analysis of market need exposes ratepayers to the very risks that regulators should be protecting them against. FERC is taking on faith that the primary justification for more pipelines, the need for more gas to supply new gas-fired power plants, will occur as projected by the applicants. With an increasing level of affiliation in precedent agreements – as much as 100 percent in certain cases – and as energy markets experience high levels of technological change and policy uncertainty, the continued reliance on this limited evidence of public benefit fails the explicit purpose of the 1999 FERC Statement of Policy.

BOX 2 - THE ROLE OF STATE PUBLIC SERVICE COMMISSIONS

State regulators of the utility sector, usually Public Service Commissions (PSCs), get to decide whether the cost of a firm transportation agreement on a new pipeline can be reasonably passed through to customers via a fuel surcharge or other cost recovery mechanism. However, it is more effective for PSCs to review a project before it is approved by FERC. In practice, this rarely happens.

If a PSC does not review a project's prudence or affiliate relationship prior to the FERC application being filed, then challenging the project after the fact becomes very difficult. A company with a FERC certificate in hand has a stronger case to make that its project is necessary given the lead federal agency's finding that it is, even though FERC has done little to verify the case. While a PSC may adjust cost recovery if it finds that ratepayers are overpaying for services, this could involve lengthy and protracted disputes.

The risk that FERC's finding may undermine value for ratepayers is greatly multiplied today with the proliferation of self-dealing and the increasing disruption in energy markets created by renewable energy and other clean energy technology. These factors require PSCs to take action immediately.

The ongoing case of the Spire STL Pipeline provides an example of where a PSC is challenging a project within the FERC certification process because of the risk that the project will needlessly increase costs to ratepayers.⁴⁴ The project would carry Appalachian Basin gas to St. Louis through a 59-mile greenfield connection with the REX pipeline system. The only precedent agreement presented to FERC in the application is with Laclede Gas, an affiliate of Spire STL Pipeline LLC.

The Missouri PSC (MoPSC) filed a Conditional Protest with FERC in February 2017 stating that "it is not clear there is a need for the project" and that Spire should not be allowed to shift the risk of the project to Laclede, which has captive customers in Missouri. Laclede also has existing contracts with other pipelines that may be impacted by the creation of overcapacity, raising costs for the captive customers of those projects. The MoPSC also questions the 14 percent return on equity the company has proposed.

In a sign of the difficulties PSCs face challenging cost recovery on projects approved by FERC, MoPSC requests FERC not to approve terms in the precedent agreement between the pipeline developer and its affiliate. It states that it "wants to avoid any future arguments that the Commission's approval of the terms to the Firm Transportation Service Agreement contained within Spire's Precedent Agreement somehow preempts the MoPSC's jurisdiction relating to Laclede's charges to its Missouri retail customers."

In the Spire Pipeline case, the Missouri PSC is doing its job in seeking to protect ratepayers under its jurisdiction from bearing the cost of unneeded pipeline capacity.

PSCs in other states where captive utility ratepayers are at risk from pending pipeline projects, including in Virginia, North Carolina, New Jersey, New York, and Michigan, should lodge the same concerns with FERC. The North Carolina Utilities Commission took a step forward in 2015 when it argued to FERC that the Atlantic Coast Pipeline's proposed 14 percent return on equity is not justified by current market conditions.⁴⁵ PSCs should go further and press FERC immediately to verify market need for new pipelines before they are certified.

RATEPAYERS BEAR THE RISK AND THE COSTS OF PIPELINES

Whether the pipeline owners are solely in the pipeline business, or are affiliated with gas producers or utilities, the costs of financing, building, and operating a pipeline will ultimately be paid for by the retail customers, either for the gas or for the electricity produced from the gas. This would be a standard market transaction that would place the risk of investment in supply infrastructure on the developer if it were not for the structure of regulated utility cost recovery.

Regulated utility companies can recover the cost of fuel for power plants or fuel delivered to customers through a fuel surcharge that is regulated by the state public service commissions (see Box 2). Included in the fuel surcharge is the transportation cost of getting that fuel

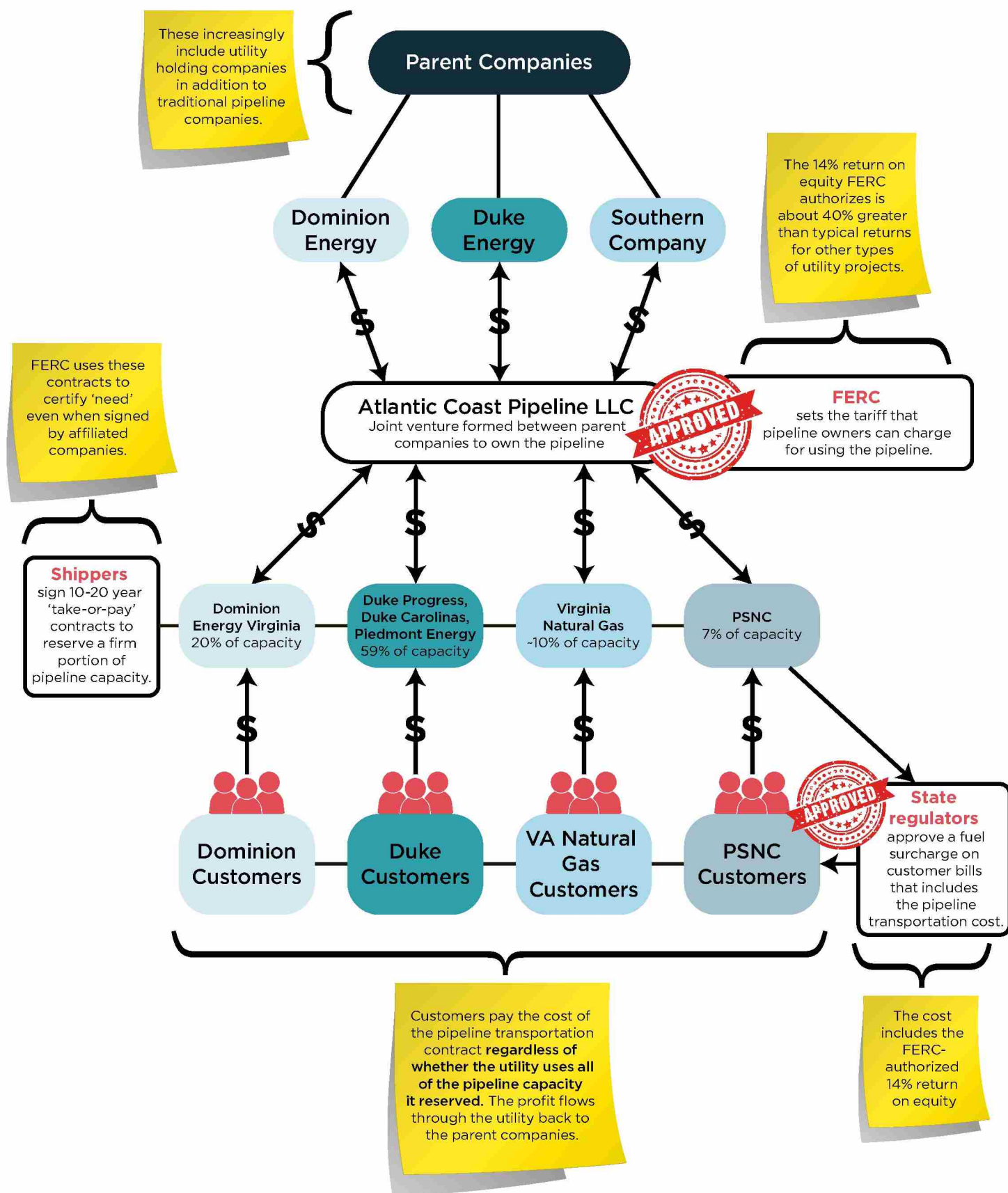
to power plants and customers. However, while the cost of and demand for gas can fluctuate and be reviewed and adjusted regularly (i.e. annually), the transportation cost is often committed for as long as 20 years.

The 'firm transportation agreement' is a bulwark of the pipeline business model. Most pipeline projects would not get financed and built without a substantial proportion of capacity reserved under such agreements. The contract is agreed between the pipeline owner and shippers of gas on the pipeline. The shipper commits to pay for a specified amount of capacity on the pipeline on a daily basis. This contract reserves space on the pipeline whether or not it is used and ensures the shipper can access the pipeline at all times of high demand at a predictable price. This type of contract is also known as 'take-or-pay.'

Such a contract is in some ways similar to an insurance policy for both parties. Shippers ensure there will be enough capacity available in times of high demand; pipeline developers get some guarantee of revenue to offset the large upfront costs of building a pipeline.

For a new pipeline to go ahead, investors commonly require these contracts for the first 10 to 20 years of the project to ensure the return of a significant proportion of capital invested. The actual depreciation rate of a project may be longer than these initial contracts, but they provide an acceptable level of risk sharing between lenders and project developers. Therefore, when new pipelines are planned, precedent agreements are usually signed between pipeline developers and shippers that secure long-term 'firm service' early in the process of project planning. This reduces risk for lenders and is also presented to

Figure 4: How Utility Customers Will Ultimately Pay for the Atlantic Coast Pipeline



regulators as evidence that the pipeline serves a market need.

A problem with this structure arises when regulated utilities are involved anywhere in the chain of supply. Since the cost of a long-term commitment to pay for firm service may be passed on to the ratepayer through the fuel surcharge (as illustrated in Figure 4), the risk of contracting for long-term service is shifted to the ratepayer from the utility making the commitment.

When a utility holding company invests in pipeline development, and its utility subsidiary signs a precedent agreement for long-term firm service with its pipeline subsidiary, the cost of the pipeline investment can be paid for by the captive customers of the utility. With state regulatory approval (see Box 2), the cost of the firm service agreement can be incorporated into a fuel surcharge. Therefore, captive customers may bear the cost of developing the pipeline, plus the generous FERC regulated return on equity (discussed next), passing fees through the utility to the utility holding company's pipeline subsidiary.

This ability for utility holding companies to pass through the cost and risk of pipeline development to captive customers provides an incentive to construct new pipelines where they may not be needed. This is happening today with the newly commissioned Sabal Trail Pipeline in Florida (see Box 3).

This may also raise costs for ratepayers on existing systems. Not only are new pipelines more expensive to use than old ones, but the creation of overcapacity raises costs for underutilized existing pipelines.

FERC tariffs are based on the depreciated value of the pipeline. A new pipeline has a higher value than an older one because it has not been depreciated. Supplying gas through new pipelines results in significantly higher transport costs than using existing pipelines because those pipelines have been mostly paid for by previous users. The higher transport costs become part of the overall fuel cost that is passed through the utility to the ratepayers. If the new pipeline results in lower utilization of existing pipelines, as is happening on the Sabal

Trail Pipeline (see Box 3), then operators of existing pipelines must raise their rates, thereby raising costs for everyone.

Former FERC commissioner Norman Bay warned of this increasing risk in his parting statement issued in February 2017. "If a new pipeline takes customers from a legacy system," Bay cautioned, "the remaining captive customers on the system may pay higher rates."⁴¹

This dynamic is already starting to emerge. Two pipeline systems in the Midwest – Tallgrass Interstate Gas Transmission and Great Lakes Gas Transmission – have cited diminishing future flows of gas through their systems in cases before FERC seeking rate increases. Testimony filed on behalf of both companies points to increasing competition not only from other systems but also from alternative energy options.⁴²

"As technology advances and the prices of alternative energies decline, alternative energies may become the economic choice for many energy consumers," wrote Alexander Kirk, an expert witness who filed testimony in both cases. "Alternative energies, such as wind and solar, are likely to offer a viable competitive alternative to natural gas, particularly over a 35-year period."⁴³

When federal regulators certify pipelines without a fair evaluation of the need for them, they risk causing an unnecessary increase in the costs consumers pay for gas or for electricity generated by gas-fired power plants. This regulatory failure results in increased rates that are no longer "just and reasonable." Customers have no say in whether a pipeline is built, state protections are circumvented, ratepayers are discriminated against, and pipeline developers' interests are preferred.

Where utility holding companies invest in pipelines to sell capacity to themselves, intense scrutiny needs to be placed upon the prospects for overcapacity in the system and the risk to ratepayers. Comprehensive reassessments of market need must be carried out on pending pipeline projects involving utility self-dealing immediately, and particularly regarding the four pipelines studied in this report.

FERC RATE SETTING DISTORTS PIPELINE INVESTMENT DECISIONS

In general, one would assume that rational market actors, such as corporations, would not invest capital in overcapacity if they can avoid it. Above we have detailed how at least some of the risk of these gas pipelines may be borne by captive customers of affiliated utility partners in the projects. We have also discussed how regulators are not doing a diligent job of assessing the market for expanded pipeline capacity, particularly in cases of significant self-dealing. But given state regulators could at some point push the risk back to the utilities that are affiliated with pipeline developers, why would a corporation pursue projects that result in overcapacity?

We know from basic finance theory that an investor's appetite for risk grows with the promise of higher returns.⁵² It is therefore a significant factor that the rate of return for greenfield interstate gas pipelines, as set and regulated by FERC, is higher than for many activities investors can engage in today.

FERC sets the tariffs that the owners of a pipeline can charge companies that are shipping gas through a pipeline (shippers). Shippers are usually gas producers, utility companies or gas marketing company traders.

The tariffs that FERC authorizes are based on a rate of return for the project that the Commission deems reasonable. A 14 percent return on equity (ROE) has been standard for greenfield interstate gas pipelines since 1997.⁵³ This can be traced back to a decision on the Alliance Pipeline that year and has been used since as a precedent.⁵⁴ Fourteen percent is much higher than the rate most financial activities can expect to earn today. This may be luring companies into the pipeline development business that would otherwise not be there.

In 1997, the U.S. Prime Rate of Interest, the interest rate charged by banks to their most creditworthy customers, was between 8.25 and 8.50 percent.⁵⁵ Since the financial crisis of 2008 that rate has hovered between 3 and 4 percent and today it is at 4.25 percent.⁵⁶ This means that

BOX 3 - SABAL TRAIL: A WARNING SIGN FOR UNNEEDED PIPELINE CAPACITY?

The Sabal Trail pipeline is one of the first major new greenfield pipelines of the current wave to come online. The 515-mile interstate gas pipeline is designed to eventually carry more than 1 Bcf/d of gas from Alabama, where it interconnects with the Transco Pipeline, across Georgia and into central Florida. The pipeline is a joint venture of Spectra Energy (owned by Enbridge), NextEra Energy, and Duke Energy. Its main customers are utility affiliates of NextEra and Duke: Florida Power & Light and Duke Energy Florida.

Data from the pipeline's first week of preliminary service, which began on June 6, 2017, indicates the project is taking capacity away from existing pipeline systems, rather than supplying additional volumes of gas to its destination market of Florida.⁴⁹

An analyst with BTU Analytics found that the Sabal Trail pipeline carried 250 million cubic feet per day (Mmcf/d) of gas from the Transco system and delivered it to end-users in central Florida

during its initial week of service. Before Sabal Trail came online, the same market had been served primarily by the Florida Gas Transmission and Gulfstream pipelines. The week before Sabal Trail's start-up, those two pipelines received as much as 750 Mmcf/d of gas from the Transco Pipeline. The week of Sabal Trail's start-up, those pipelines received about 500 Mmcf/d from Transco, a fall off roughly equal to the amount taken on by Sabal Trail. Thus, as Sabal Trail began service, it led to less utilization of competing pipeline systems, not increased incremental demand for gas.⁵⁰

Flattening power demand in Florida suggests this trend could continue. The BTU analyst concludes that, "The challenge is natural gas in Florida faces growing competition from residential, commercial and utility scale solar resources as well as power forecasts that are revising lower despite a growing population and customer counts."⁵¹ That situation is not unique to Florida.

pipeline developers today can access debt at half the rate they could in 1997, but can still charge customers tariffs that reflect a cost of capital that has not been relevant for over a decade.

Further, this rate of return is significantly higher than typical rates FERC sets for other utility activities it regulates. It is around 40 percent higher than the typical returns – of about 10 percent – that companies can expect to receive for power plants⁵⁷ and FERC-authorized interstate electric transmission projects.⁵⁸ This excessive rate of return distorts investment decisions, especially in an era of low interest rates, which already lessen the long-term costs of major capital investments.⁵⁹

FERC has acknowledged in the Commission's February 1999 Statement of Policy the damage that sending incorrect price signals can cause. At the time, the Commission was concerned with the subsidization of pipeline expansions by existing customers through raising rates to provide capital for an expansion. The Policy Statement warned that:

Sending the wrong price signals to the market can lead to inefficient investment and contracting decisions which can cause pipelines to build capacity for which there is not a demonstrated market need. Such overbuilding, in turn, can exacerbate adverse environmental impacts, distort competition between pipelines for new customers, and **financially penalize existing customers of expanding pipelines and customers of the pipelines affected by the expansion.**⁶⁰

Unfortunately, the Commission is ignoring its own policy guidelines and is awarding excessive rates of return for gas pipelines despite many complaints and recommendations for review.⁶¹ By contrast, FERC is reviewing cases of excessive returns in some wholesale power markets.⁶² In addition, it finalized incentives for electricity transmission line investment in March 2017.⁶³ This policy set a 10 percent return with some additional incentives for specific cases. The Commission should take the same microscope to the rate of return allocated to gas pipeline developers before it issues any more permits.

As the utility sector faces stagnant or declining revenues from electricity sales (see Section 3 below), companies are increasingly lured into the gas pipeline business in search of higher returns. At the same time, traditional pipeline developers continue to propose their own projects, leading to a rush of pipeline proposals driven more by the expectation of high returns than by any consideration of long-term gas demand.

As long as FERC continues to set high rates of return companies will continue to have a strong incentive to build more pipelines. It is imperative that FERC review the 14 percent return on equity on greenfield pipelines before issuing certificates for any of the current pending projects.

CASE STUDIES:

ATLANTIC COAST PIPELINE

Plans for the proposed Atlantic Coast Pipeline (ACP) provide an excellent example of where utility holding companies pursuing high returns from pipeline development risk undermining the public good.

The project is owned by three utility holding companies, Dominion Energy (48%), Duke Energy (47%), and Southern Company (5%). Dominion Energy will be the pipeline developer and operator. The pipeline's total capacity would be 1.5 Bcf/day. Precedent agreements have been signed for 96 percent of the pipeline capacity for a period of 20 years. However, Duke Energy subsidiaries have reserved over 59 percent of the total capacity, while a Dominion subsidiary has booked 20 percent and a subsidiary of Southern Company has booked a further 10.3 percent. Therefore, over 89 percent of the total pipeline capacity has been reserved by affiliated companies, or 93 percent of the reserved capacity.

Using tariffs filed with FERC, we can compare the cost difference between using existing pipelines and building new pipelines to serve the same need.

In the fall of 2015, a connection was made to the existing Transco pipeline through Virginia to serve a new Dominion gas-fired power plant: the 1,358 MW Brunswick County Power Plant. A four-mile extension is planned to connect the 1,588 MW Greenville County Power Station (currently under construction), scheduled for startup in late 2018. Both plants will be operating and supplied by the Transco connections before the ACP would be constructed. The connections to the Transco mainline are called the Virginia Southside Expansion Projects I and II.

Map of Atlantic Coast Pipeline Route



Table 1: Transportation Costs via the Atlantic Coast Pipeline vs. Transco (prices are per Dekatherm and rounded)

ACP	DTI Supply Header	Total ACP ⁶⁵	Transco Southside ⁶⁶	Difference
\$1.72	\$0.15	\$1.88	\$0.53	\$1.35

Table 2: Sum of Gas Hub and Pipeline Transport Costs Shows ACP is More Expensive

Gas Hub/Price	Pipeline/Price	Total Cost	Difference
Dominion South / \$2.79	Atlantic Coast / \$1.88	\$4.67	\$1.02 / 28%
Transco VA-Carolinas / \$3.12	Transco Southside / \$0.53	\$3.65	

(Gas hub prices in U.S.\$/MMBtu, based on May 2017)

In its application to FERC and in public media campaigns, the ACP has been repeatedly promoted as a way to deliver lower cost gas to Virginia and North Carolina. In a July 2017 press release, the company claimed yet again that the ACP will “lower energy bills for consumers and businesses” in Virginia and North Carolina.⁶⁴ This is possible only if the price of delivered gas using the ACP is less than the delivered price of gas from other existing pipelines serving the state.

Comparing transportation costs published with FERC shows that the cost of transporting gas to Dominion’s new power plants in southern Virginia would be 3.5 times higher using the ACP compared to the existing Transco pipeline (See Table 1).

The total price of delivered gas would be the commodity price of the gas plus the cost to transport it. Using average natural gas prices from the two supply hubs serving these two options in May 2017, we can compare the total cost of delivered gas to southern Virginia. While gas was slightly

cheaper at the Dominion South hub that would serve ACP, the higher transportation cost means gas delivered by ACP in this case is 28 percent more expensive than that delivered by Transco.

If ACP is built and its cost factored into a fuel surcharge or other rate-based mechanism, Virginia ratepayers would pay a higher cost for a service they already get. Profits would flow to the utility holding companies that own the pipeline – Dominion Energy, Duke Energy, and Southern Company – not their regulated utilities.

Existing pipelines have access to gas supplies from both the Gulf Coast and the Appalachian Basin. This means utilities in Virginia and North Carolina have flexibility in selecting the lowest-cost gas from multiple locations. Although the ACP claims that it is the “only way” to access cheaper Appalachian gas, the ACP would source gas from one regional market hub, the Dominion South hub in West Virginia.

Lower prices in certain gas production zones are usually due to constraints in getting the gas to market. This has been a factor in prices being lower in some parts of the Appalachian Basin compared to the national price set at Henry Hub in Louisiana. Several recently commissioned pipelines, together with those currently under construction, will serve to balance the available pipeline capacity from the Appalachian Basin with production volumes for several years to come. This is bound to equalize prices between production zones.⁶⁷ Indeed, the more pipelines that are built to serve any gas production region, the more prices in that region will balance with national prices. If the price of gas at regional hubs becomes aligned with the national average, the cost of pipeline transportation becomes the deciding factor in whether the delivered price is a good deal for end users or not.

IF ACP IS BUILT AND ITS COST FACTORED INTO A FUEL SURCHARGE OR OTHER RATE-BASED MECHANISM, VIRGINIA RATEPAYERS WOULD PAY A HIGHER COST FOR A SERVICE THEY ALREADY GET. PROFITS WOULD FLOW TO DOMINION ENERGY, DUKE ENERGY, AND SOUTHERN COMPANY.

MOUNTAIN VALLEY PIPELINE

The proposed Mountain Valley Pipeline would run over 300 miles from northwestern West Virginia to south central Virginia, feeding 2 Bcf/d of gas into the existing Transco Pipeline. The pipeline would cross pristine forests, headwaters, and steep fragile terrain, as well as many farms, communities, and other properties all along its path. The project is owned by five companies that are all heavily invested in gas: EQT Midstream Partners (45.5%), NextEra Energy Resources (31%), Con Edison Transmission (12.5%), WGL Midstream (10%), and RGC Midstream (1%). EQT Midstream (EQM), a subsidiary of EQT – the largest gas producer in the Appalachian Basin – will operate the pipeline.

Each of the Mountain Valley Pipeline's five shippers are affiliates of the pipeline's owners. In other words, precedent agreements struck between affiliated companies account for 100 percent of the pipeline's capacity, and are the entire basis for the 'need' of the pipeline as presented to FERC.⁶⁸ EQT, parent of pipeline owner EQM, is under contract for 65 percent of the pipeline's daily capacity. This signals that the project is primarily designed to help EQT monetize its gas reserves – not fill a gap in market demand. Despite the project's self-dealing nature, FERC has not yet questioned its purpose or need at all.⁶⁹

Two of the companies behind the Mountain Valley Pipeline are positioned to shift investment risk directly from shareholders to captive utility customers: Consolidated Edison, which owns a major utility in New York, and RGC Midstream, an affiliate of a gas utility in Virginia. While neither WGL nor NextEra have involved their utility arms directly in their pipeline transaction to date, both companies have major utility affiliates, suggesting ratepayers could end up on the hook.

Map of Mountain Valley Pipeline Route



Con Ed's affiliate dealings are drawing scrutiny in New York. Con Ed's New York affiliate did not sign up for service from the project during the open season (when the pipeline advertises its project to shippers in order to gauge market interest). However, shortly after Con Ed formed a midstream company to take an ownership interest in the project, Con Ed's regulated utility committed to take service from the pipeline for 20 years. The MVP project is

approximately 400 miles south of New York and cannot increase deliverability into Con Ed's service territory.⁷⁰ The Environmental Defense Fund has estimated that, if regulators allow the costs of this fixed 20-year contract to be passed through to ratepayers, Con Ed customers could end up paying over \$60 million per year in largely excess costs.⁷¹ All of these factors suggest significant self-dealing.

PENNEAST PIPELINE

The proposed PennEast Pipeline would carry up to 1.1 Bcf/d of gas about 120 miles from northeastern Pennsylvania, southeast through Pennsylvania, and across the Delaware River into New Jersey, terminating north of Trenton. The pipeline would bisect the Delaware River watershed, crossing forests, habitats for endangered species, farmland, communities, and water supplies along its path. Five companies each own a 20 percent stake in the joint venture: NJR, an affiliate of New Jersey Natural Gas, Southern Company Gas, UGI Energy Services, SJI Midstream, and Spectra Energy Partners (now owned by Enbridge).

All the owners of PennEast apart from Spectra are affiliated with Local Distribution Companies (LDCs) in Pennsylvania and New Jersey. LDC affiliates of the pipeline owners account for nearly 50 percent of the precedent agreements presented to FERC as proof of ‘need’ for the project.⁷²

In response to FERC’s failure to further analyze the ‘need’ for the pipeline, the New Jersey Rate Counsel, an independent state agency that represents the interests of utility customers, filed its own assessment with FERC.⁷³ The Rate Counsel concludes that the ‘need’ for the pipeline “appears to be driven more by the search for higher returns on investment than any actual deficiency in gas supply or pipeline capacity to transport it.”⁷⁴ The Rate Counsel points to peak daily gas demand projections from six area LDCs that would be served by PennEast. Those projections indicate demand will remain stable through 2020, and that little-to-no additional pipeline capacity is required to meet it.⁷⁵ The Rate Counsel further contends that three existing gas pipeline systems serving the region have a “glut of underutilized capacity.”⁷⁶

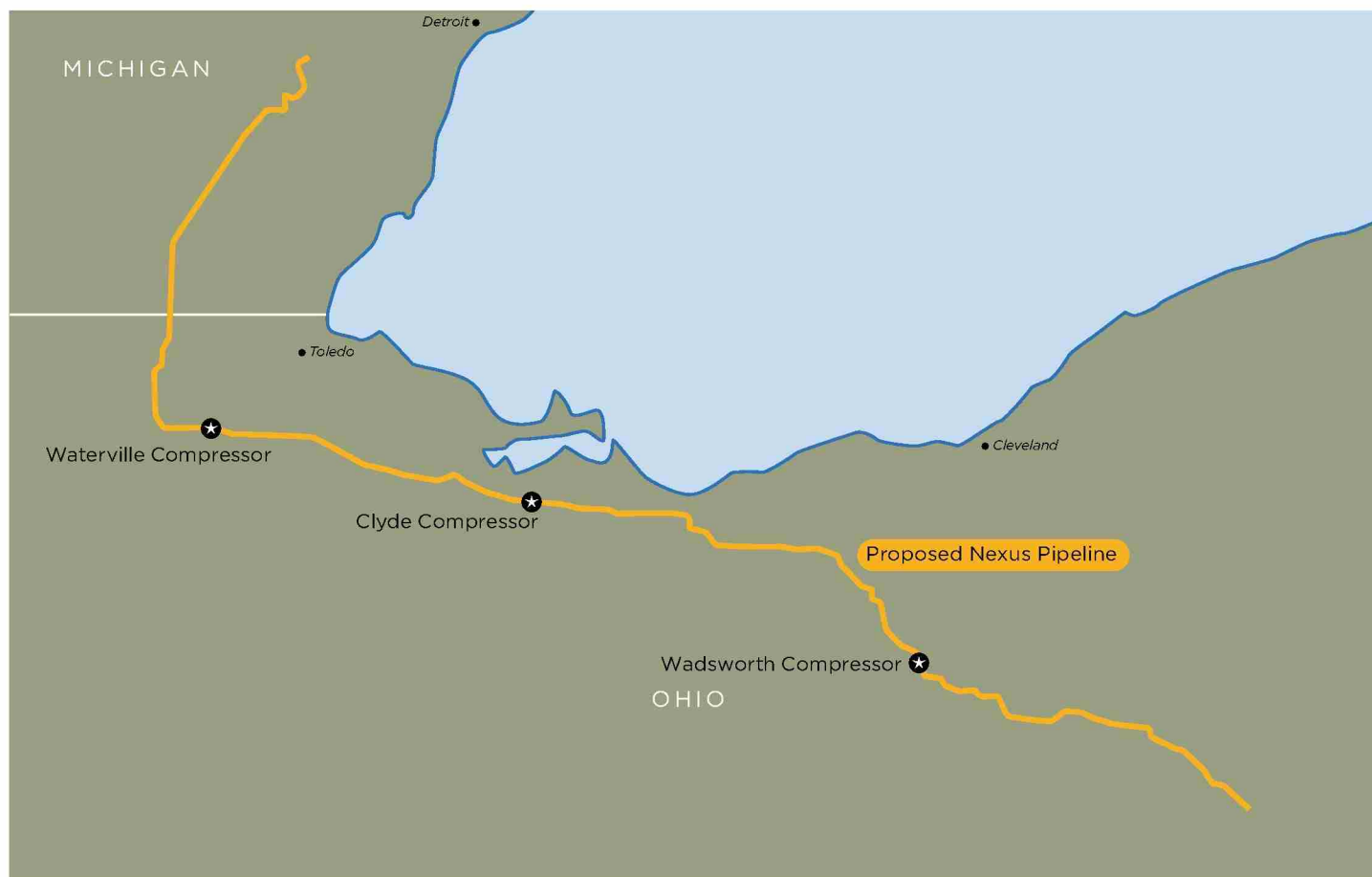
Map of PennEast Pipeline Route



To underscore the potential cost burden to ratepayers, the Rate Counsel highlights that three of the affiliated LDCs that have signed precedent agreements with PennEast – New Jersey Natural Gas, South Jersey Gas, and Elizabethtown Gas – are currently authorized by New Jersey state regulators to receive returns ranging from

9.75 percent to just over 11 percent.⁷⁷ If FERC authorizes the higher rate of return requested by PennEast’s affiliated owners, New Jersey customers will end up paying for it in their bills. The Rate Counsel calls this “tantamount to winning the lottery” for the pipeline owners.⁷⁸

Map of Nexus Pipeline Route



NEXUS PIPELINE

The NEXUS Pipeline would carry up to 1.5 Bcf/d of gas approximately 255 miles from northeastern Ohio, across northern Ohio, and into southeast Michigan, linking up to pipeline systems serving Canada and other Midwestern markets. The NEXUS Pipeline is a 50-50 partnership between two companies: DTE Energy and Spectra (owned by Enbridge). FERC issued a permit for the project in late August 2017.

Only 59 percent of the NEXUS Pipeline's potential 1.5 Bcf/d of gas capacity is filled by precedent agreements.⁷⁹ The NEXUS project would follow a similar route and serve the same market as Energy Transfer Partners' 3.25 Bcf/d Rover Pipeline, which has already caused a string of spills and air and water violations during the construction phase.⁸⁰ It also serves the same market as TransCanada's mainline, which moves gas eastward from Western Canada. TransCanada recently slashed its own tariffs to better compete with the Rover and NEXUS projects.⁸¹

As discussed previously in Section 2, FERC conducted no independent assessment to verify long-term market demand for the project before issuing its Certificate Order in August 2017.⁸² Instead, FERC took at face value the companies' claims that the project is needed to serve growing demand from the electric power sector and that the NEXUS project "is not intended to replace service on other pipelines."⁸³ However, DTE executives have essentially acknowledged that the NEXUS Pipeline is not intended – and not needed – to increase regional gas supply.

In an April 2017 conference call with investors, DTE's CEO and president tried to ease concerns about whether there's "room for three pipes" going into the region (a reference to Rover and the TransCanada mainline) by stressing that NEXUS is designed to "displace supplies" coming from Western Canada, not add additional gas supply.⁸⁴ Thus, by the company's own admission to investors, NEXUS is not filling a supply gap but displacing existing sources of gas in the region.

While the NEXUS Pipeline has a lower level of affiliate self-dealing relative to other pipelines highlighted in this report, DTE customers in particular could end up paying a high price. Two DTE utility subsidiaries in Michigan – DTE Electric and DTE Gas – have signed 15-year contracts to together utilize up to 17 percent of the pipeline's subscribed capacity (or up to 10 percent of its potential full capacity).⁸⁵ These DTE subsidiaries sought approval from Michigan regulators to pass costs related to the NEXUS Pipeline on to their customers even before the project had received federal approval.⁸⁶ The Michigan Attorney General and TransCanada – which owns the competing ANR Pipeline – have both argued that DTE's Michigan utilities did not properly consider alternatives before signing contracts with their unregulated parent company to purchase pipeline capacity from the NEXUS project.⁸⁷ Acknowledging these concerns, Michigan regulators have said they will require "a transparent evidentiary presentation examining the full nature of the NEXUS arrangements" before approving DTE's cost-recovery plans.⁸⁸

Solar panels installed on the roof of a county building in Gaston County, North Carolina.



3. SHIFTING ENERGY TRENDS: DECLINING DEMAND AND CLEAN TECH MAKE GAS LOCK-IN A RISKY DEAL FOR RATEPAYERS

Energy trends are shifting both in the United States and globally. Technology coupled with environmental policies, whether climate or air quality focused, are enabling consumers and businesses to do more with less energy. Clean energy technology, in the form of renewable energy, storage, and grid management technology, is enabling a shift away from all fossil fuels, enhancing energy choice, security, cost competitiveness, and the environment. Further, these shifts are only just building momentum and we are likely still unable to gauge their full potential.

In the United States, numerous analysts have noted a “decoupling” between economic growth and energy demand growth.^{89,90} In other words, for the first time in modern history, the economy is growing but energy demand is not. Further, while there is substantial new generating capacity being planned and built, much of it is designed to replace retiring and uneconomic capacity. Finally, one of the established tenets of the gas industry, that new gas replaces dirty coal, is unravelling. Renewable energy and efficiency is today cost competitive with both coal and gas. Together with a spate of imminent gas power plant retirements, this throws into question the assumed relationships between new gas plant build, gas demand growth, and emissions reductions.

U.S. ENERGY DEMAND AT A CROSSROADS

While U.S. oil and gas production has been soaring, long-term trends in energy use are starting to reach a tipping point. For decades, energy use per capita has been in decline, falling 14 percent between 2000 and 2016.⁹¹ Similarly, energy use per real dollar of GDP fell nearly 26 percent in the same period.⁹² While energy efficiency has been improving since the 1970s, rising population and economic growth have generally kept the total amount of energy used growing, except in times of recession. In other words, there has been a general link between economic growth and energy demand. However, recent trends have thrown that link into question and, as technology develops at an ever-quicken pace, the future looks to be one in which different fuel sources and technologies will have to compete in a shrinking market.

Figure 5 shows the relationship between U.S. economic growth and power generation since 2002. While it is clear that power generation generally followed growth upwards before the crash of 2008 and recovery in 2010, the relationship has been far less clear since 2011. Until then, energy demand and economic growth went generally in the same direction, albeit at differing intensities. But since 2011, they have gone in different directions for three of

the six years, and the relationship appears much weaker in those years where they were linked. Overall, power demand has flattened since 2011 amid steady economic growth.

The Sustainable Energy in America Factbook 2017, produced by Bloomberg New Energy Finance (BNEF) and the Business Council for Sustainable Energy, had the following to say about the long-term trend: “The US has truly ‘decoupled’ economic growth from energy demand: since 2007, US GDP is up 12% while overall energy consumption has fallen by 3.6%.”⁹³ The report goes on to note that U.S. utilities tripled spending on energy efficiency to \$6.3 billion between 2007 and 2015.

The American Council for an Energy-Efficient Economy (ACEEE) reported last year that in 2015, energy efficiency became the “third largest electricity resource in the United States.” When counted as a source of electricity, energy efficiency accounted for 18 percent of total generation compared to 16 percent for nuclear power. The ACEEE projects that this rate can almost double by 2030, with energy efficiency accounting for 33 percent of potential generation by that time. If this rate of efficiency improvement is achieved, then the output of the equivalent of 487 average power plants will not be required in 2030.⁹⁴

While it remains unclear that those efficiency gains will happen in that time frame, recent projections for the U.S. power sector that include current investment trends point to substantial changes ahead. The BNEF New Energy Outlook 2017 (NEO), published in June, sees U.S. electricity demand growing at a tepid 0.25 percent per year to 2040.⁹⁵ But even that small growth projection comes with a number of caveats. BNEF sees most of that growth happening in the “sunshine states” of California, Texas, and Florida, meaning that much of it will be met by solar and wind energy that is already well developed in the first two of those states and beginning to take a hold in the third. Other states are likely to see stagnant demand followed by decreases due to efficiency.⁹⁶

According to the NEO analysis, the only likely source of electricity demand growth will come from the growth in electric vehicles (EVs).⁹⁷ However, BNEF projects that many EVs will be integrated into a flexible charging system that takes advantage of periods of high renewable energy production, meaning that the main prospect for power demand growth is not likely to provide a boost for gas-fired generation.

That the traditional utility model is evolving due to declining demand and technology

disruption appears almost universally accepted in the sector. Utility Dive reported in May 2017 that in their recent survey of utility professionals, 90 percent said they are exploring new opportunities around distributed energy resources, while only 5 percent thought that their business model does not need to evolve.⁹⁸

FORECASTS FOR GAS POWER DEMAND ARE HIGHLY UNCERTAIN

The NEO 2017 projects that gas demand in the U.S. power sector will only be 4.8 percent higher in 2040 than it was in 2016. This is half as much growth as that projected by the EIA in its 2017 Annual Energy Outlook.⁹⁹ The EIA’s long-term energy projections are notoriously inaccurate but are consistently used by government and industry to inform policy and investment.^{100,101} However, even the level of growth projected by BNEF may be optimistic given accelerating trends in the energy landscape.

Gas Plants May be Built, But How Much Capacity Will They Add?

There are many gas power plants currently planned in the United States.¹⁰² But there are disconnects between the amount of new capacity projected to be built and the prospects for substantially increased gas demand. The NEO projects that 178 GW of

new gas-fired generation capacity could be added from 2018 to 2040, but the projected net increase in capacity is less than 50 GW. This is because over 128 GW, or 72 percent of the projected gas-fired capacity additions, would replace retiring inefficient gas plants. The net increase in capacity would be only 11 percent.

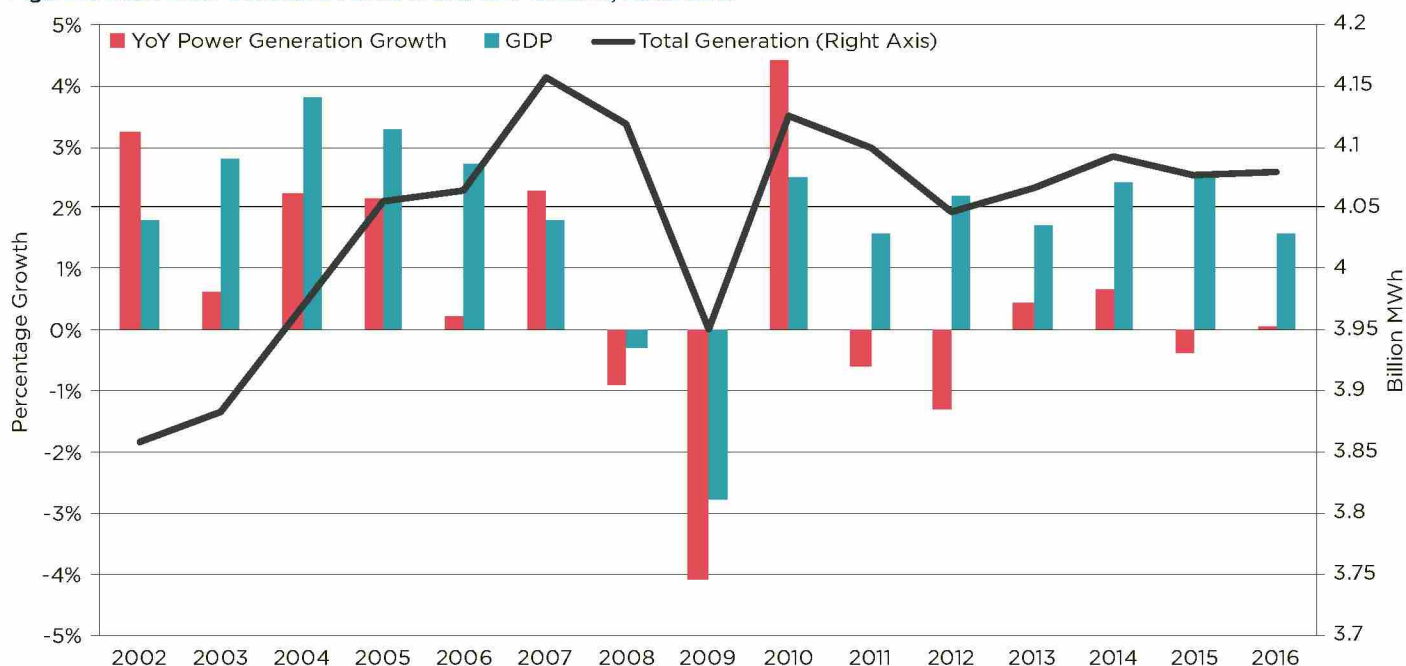
If they are built, these new plants will be more efficient than the retiring plants so the percentage increase in gas demand would not correspond with the increase in net generation capacity.

Clean Energy is Increasingly Cost Competitive

The NEO projects that over 90 GW combined of both battery storage and demand response will be in place by 2040. By 2023, unsubsidized utility-scale new-build wind and solar photovoltaic (PV) systems will be cost competitive with new-build gas power across all of the United States. According to the latest Integrated Resource Plan from Dominion Energy, solar is already the cheapest source of energy in Virginia, which leaves many to question whether Dominion’s Atlantic Coast Pipeline project is needed.¹⁰³

Five years later, in 2027, new-build solar PV will be cost competitive with existing gas capacity across the United States, even in

Figure 5: U.S. Power Generation Growth and GDP Growth, 2002-2016



Source: EIA



the least sunny and windy states. As the cheapest source of electrons in the market at any given time is generally dispatched first, gas-fired power will have to compete with both a larger number of generation choices, as well as those that enjoy very low marginal costs of production.

Gas Plants are at Increasing Risk of Underutilization

The ‘capacity factors’ of gas plants, or their actual power output compared to their maximum potential output, is increasingly challenged by competing sources of generation. This is another major factor suggesting gas demand in the power sector may decline.

The cost of generation at any given time compared to other generation sources available in the market generally governs how long a gas plant is burning gas and generating power. It is clear that gas-fired generation will increasingly have to compete in wholesale markets with a growing number of cost effective competitors, particularly renewable energy sources. This could mean that gas plants are ‘dispatched’ only when electricity demand exceeds the capacity of cheaper sources of power. This is a growing problem for gas generators as more renewable energy and storage, which has zero fuel cost at the time of dispatch, comes online.

The high availability of renewable energy is already reducing the capacity factor of gas plants in California, leading to a reduction in gas burn in that state large enough to be felt nationally. Average gas plant capacity factors in California were down to 20 percent in 2016 through August, which was 4 points below the ten-year average.¹⁰⁴ Some plants were down as low as 7.5 percent.¹⁰⁵ This was before the heavy rains that filled many of the hydroelectric reservoirs in the region following years of drought, which has led to even greater market share loss for gas. In the first half of 2017, power generated from gas in California was down 19.2 percent year-on-year.¹⁰⁶

The decline in demand for gas-fired power in California is a major factor in a projected 21 percent reduction in gas burn for power nationally in 2017.¹⁰⁷ This reversal in the trajectory of gas-fired power generation is being felt beyond California.

Flattening Demand Already Raising Questions

The decline in gas-fired generation in 2017 is raising questions among analysts and commentators watching the U.S. gas market. Energy advisory firm BTU Analytics has published several articles in recent months questioning the prospects for gas demand growth from the power sector. They have noted both flattening demand in the sector on the whole¹⁰⁸ as

well as the emerging competition between renewable energy and gas. In June 2017, analyst Matthew Hoza projected that renewable energy could reduce power burn of Appalachian gas in the early 2020s by around 5 percent, or 1.7 Bcf/d.¹⁰⁹ This is 13 percent more than the maximum capacity of either the Atlantic Coast or NEXUS pipelines.

In another piece by BTU Analytics, Andrew Bradford noted that the recent commissioning of the controversial Sabal Trail gas pipeline, which brings Appalachian gas into Florida markets, has led to lower flows in existing pipelines due to stagnant demand, and that prospects for additional demand in the Florida market are threatened by efficiency and renewable energy buildout.¹¹⁰

In a July 2017 article, Jack Farchy and Kelly Gilblom questioned whether “Big Oil’s bet on gas is wrong.” They noted headwinds for demand in both oil and gas, globally and in the U.S., and raised the spectre that the oil sector’s pivot to gas may be based on overly optimistic expectations.¹¹¹

It seems the only bright spot for gas producers in the first half of this year was export¹¹² and it is not export that the public convenience and necessity of pipelines proposed by utility affiliates can be based on.

BOX 4 - LNG EXPORTS: A PRIMARY SOURCE OF DEMAND GROWTH

Appalachian gas is set to be exported via LNG export plants, not only from the East Coast, but from the Gulf Coast too.¹¹³ Closer to home, Dominion Energy's Cove Point LNG export plant in Maryland will be starting up later this year.

In the first half of 2017, LNG export was the leading source of demand growth, as power burn and residential demand slumped.¹¹⁴ The potential for more Gulf Coast export capacity coming online in the next few years means it is likely that the biggest growth market for Appalachian gas will be LNG export.

The U.S. Energy Information Administration studied the impact of LNG exports on U.S. energy markets in a 2014 report, which

found that increasing exports would raise prices in the U.S. to varying degrees according to different scenarios.¹¹⁵ On average, gas bills for U.S. residential, commercial, and industrial consumers could increase between 3 and 9 percent compared to a no-export baseline.¹¹⁶

Despite the prospect that exports may become the primary source of U.S. gas demand growth, the impact of LNG exports on the price of gas, either nationally or in the Appalachian Basin, has not been considered in any of the pending gas pipeline applications before FERC today.

CLEAN ENERGY IS LOWER RISK FOR RATEPAYERS

While the future of gas demand can be debated but not proven, another issue that points to the need for greater regulatory diligence is how the risk of higher gas prices is borne. A recent study by Lawrence Berkeley National Laboratory (LBNL) offers a tool for comparing the long-term costs and risks of investing in renewable energy or gas for power generation. The study found that "renewable resources have added value as a hedge against natural gas price volatility."¹¹⁷

The study quantifies the risks of each resource – i.e. gas price volatility or low renewable energy capacity utilization – and factors them into a levelized cost of energy (LCOE) analysis. The study's author stated that, "In general, higher-than-expected gas prices appear to be riskier to ratepayers than lower-than-expected wind or solar output."¹¹⁸

A table in the study mapped out the resource risk impact on different

stakeholders illustrating how such risk is distributed (see Figure 6). It found that not only did utility ratepayers bear the most risk of either adverse outcome, but that the risk of high gas prices has a higher impact on them than the risk of low solar or wind output.

The LBNL study is just one of many analyses available that detail the enormous changes occurring in the energy space today. These changes, like energy technology and markets, are not static. FERC should be studying and analyzing these developments in great detail before issuing permits for infrastructure that poses such a risk to the key constituents it should be protecting: ratepayers.

OTHER SOURCES OF GAS DEMAND ARE VULNERABLE

Power generation has in the recent past been the main source of growth for gas demand. Other uses for gas have been flat or in decline as technology enables increasing efficiency. Residential demand (heating and cooking) in the U.S. has

remained static in recent years even as the number of connected customers has risen. Bloomberg Finance reports that, even accounting for recent mild winters, per customer consumption has dropped over 10 percent in the past decade as the result of utility investment in energy efficiency.¹²⁰

Some growth is expected in the industrial sector, with gas expected to play a larger role in petrochemical and fertilizer production especially.¹²¹ However, this growth is projected to be modest compared to the growth producers and pipeline developers are planning for. In many of the regions that new pipelines are targeting, very few specific plans have been made for new industrial facilities requiring gas.

The increasing uncertainty surrounding the future demand for gas should require FERC and state regulators to carefully scrutinize any proposal to build new gas infrastructure that would be offset through ratepayer surcharges.

Figure 6: Resource Risk Impact of High Gas Prices vs. Low Solar/Wind Output

Stakeholder	High Gas Prices		Low Solar/Wind Output	
	Utility-Owned	IPP-Owned	Utility-Owned	IPP-Owned
Independent Power Producers (IPPs)	None	None/Low	None	Moderate/High
Utility Ratepayers	High	High	Moderate	Moderate/Low
Utility Shareholders	Low	Low	Low	Low

Source: Lawrence Berkeley National Laboratory¹¹⁹

RECOMMENDATIONS

PROTECTING RATEPAYERS REQUIRES DUE DILIGENCE IN ASSESSING PIPELINE NEED

As the gas pipeline boom enters a new and more dangerous phase, the potential consequences for communities in the path of new projects, our climate, and U.S. consumers are greater than ever before.

Pipelines are multi-billion-dollar investments meant to last for several decades. In a world going through a relatively rapid and crucial energy transition, federal regulators should be applying their highest bar of scrutiny to new pipeline proposals that threaten to lock consumers into long-term reliance on gas while limiting their choice of cleaner, cheaper alternatives. Instead, the current regulatory system incentivizes companies to build thousands of miles of new pipeline without any systematic assessment of market need. It simultaneously allows pipeline developers to shunt the financial risks on to utility customers.

Before approving any more projects, the Federal Energy Regulatory Commission should undertake a comprehensive review and reform of its gas pipeline permitting processes. This includes pausing any further consideration of pending pipeline proposals, including three of the pending projects considered in this report – the Atlantic Coast Pipeline, Mountain Valley Pipeline, and PennEast Pipeline – as well as reconsidering the permit for the NEXUS Pipeline. FERC is failing to serve the public interest and is threatening to stick U.S. families with high bills by approving new projects with no more than a superficial glance at whether they are needed.

Amid an unprecedented rush of new pipeline proposals, and the rapid growth of cost-competitive energy alternatives, FERC must overhaul its pipeline permitting process to protect the interests of U.S. consumers from the profit motives of pipeline developers.

FERC should pause all permitting of new pipelines unless and until it implements necessary reforms. Specifically, FERC must:

- **Stop using precedent agreements as evidence of the ‘public convenience and necessity’ of new pipelines, especially when contracts are between affiliated companies and involve captive utility customers.** In other contexts, FERC has observed the need to protect against affiliate abuse and self-dealing.¹²² To protect customers against risk-shifting, FERC should update its policies so that affiliate precedent agreements are no longer considered acceptable proof of the need for new pipelines.
- **Thoroughly and independently assess the long-term market need for proposed pipelines – and deny permits when need is not clearly established.** FERC should analyze long-term regional demand, the efficiency and utilization of existing pipelines, cost-effective alternatives like clean energy and storage, and a broad range of factors to determine public need. This assessment would be similar in some respects to the regional planning conducted for electricity transmission.
- **The independent assessment should require an evidentiary process** – involving hearings that allow commissioners and public advocates to cross-examine industry witnesses. This is the best way to ensure a full and fair assessment of need is carried out. FERC should establish the Office of Public Participation to facilitate the engagement of impacted communities and consumer advocates in the process.¹²³
- **Reduce the return on equity authorized for new pipeline projects to reflect current market conditions.** The 14 percent return on equity has not been reviewed by FERC in 20 years, despite the current era of low interest rates. FERC should revise this rate downward to conform with current market and investment conditions and with typical

rates for comparable utility investments, including clean energy such as energy efficiency and renewable energy. Otherwise, the agency itself may be inappropriately shaping energy markets, luring companies into the pipeline business and incentivizing the construction of unneeded pipelines at the expense of ratepayers.

State PSCs also have a crucial role to play, given that their job is to protect ratepayers from unreasonable costs. When FERC fails to properly evaluate the need for new pipelines, federal regulators make it harder for state regulators to do this job. PSCs are forced to make decisions about rates based on pipeline infrastructure already deemed ‘necessary’ by FERC, and on contracts that state utilities have already signed. To protect ratepayers under their jurisdiction, state PSCs should take the following action:

- File protests in relevant FERC pipeline dockets immediately, demanding that FERC fully evaluate the market need for any new pipeline that would impact their state’s ratepayers.
- In cases where a utility has entered into a contract to buy gas from an affiliated pipeline developer, invoke their authority to review the prudence of that affiliate contract. Affiliate review statutes exist in many states to protect consumers from self-dealing transactions that do not serve ratepayers’ interests.
- Apply heightened scrutiny to determine whether rate hikes related to new pipeline transportation costs are just and reasonable, especially when affiliate self-dealing is involved.

Ultimately, when regulators fail to assess whether new pipelines are actually needed, they hand pipeline companies an opportunity to gouge U.S. consumers. Given the associated environmental risks and property rights violations, and the gathering pace of the clean energy transition, such a failure in regulatory oversight is unacceptable.

REFERENCES

- 1 Calculation based on FERC data on major approved and pending projects as of July 2017. This calculation includes pipelines that would add 100 or more miles of new takeaway capacity out of the Appalachian Basin specifically, and that were already approved in 2017 or could be approved in 2017. See FERC, "Approved Major Pipeline Projects (2009-Present)," <https://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp>; FERC "Major Pipeline Projects Pending (Onshore)," <https://www.ferc.gov/industries/gas/indus-act/pipelines/pending-projects.asp>.
- 2 Anastacia Dialynas, "U.S. Gas Insight: Pipelines to boost App Basin Takeaway. Forecasted build-out of App Basin Gas Pipelines, 2017-18," March 2, 2017, Bloomberg New Energy Finance. Available by subscription from www.BNEF.com.
- 3 Lorne Stockman, "A Bridge Too Far: How Appalachian Basin Gas Pipeline Expansion Will Undermine U.S. Climate Goals," Oil Change International, July 2016. <http://priceofoil.org/2016/07/22/a-bridge-too-far-report/>
- 4 Based on U.S. Prime Rate: http://www.fedprimerate.com/wall_street_journal_prime_rate_history.htm
- 5 "Cost-of-Service Rate Filings," Federal Energy Regulatory Commission, January 19, 2017. <https://www.ferc.gov/industries/gas/gen-info/rate-filings.asp>
- 6 Norman Bay, "Order Granting Abandonment and Issuing Certificates; BAY, Commissioner, Separate Statement," FERC Docket No. CP15-115-000, February 3, 2017, p. 3. <https://www.ferc.gov/CalendarFiles/20170203194955-CP15-115-000.pdf>
- 7 Appalachian Mountain Advocates, "2nd Revised Motion to Answer and Answer of Appalachian Mountain Advocates et al. under CP16-10," FERC Docket No. CP16-10, March 31, 2017, pp. 3-6. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14554557
- 8 Environmental Defense Fund, "Case No. 93-G-0932 - Heightened Scrutiny of Precedent Agreements Supported by Affiliates," New York State Public Service Commission Case No. 93-G-0932, November 29, 2016, <http://documents.cps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=963713D9-6F89-4E4F-AA49-896933895B51>
- 9 New Jersey Division of Rate Counsel, "Comments of the New Jersey Division of Rate Counsel under CP15-558 (Draft Environmental Impact Statement for the PennEast Pipeline LLC)," Federal Energy Regulatory Commission, September 12, 2016, p. 8. https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20160912-6003
- 10 See Michigan Public Service Commission, "Order," Case No. U-17691, November 22, 2016, p. 14-22. http://www.michigan.gov/documents/mpsc/u-17691_11-22-16_569183_7.pdf and Michigan Public Service Commission, "Order," Case No. U-17920, January 12, 2017, p. 3-4. http://www.michigan.gov/documents/mpsc/u-17920_1-12-17_565190_7.pdf
- 11 Natural Gas Act of 1938, Section 7 (15 USC §717f)
- 12 Federal Energy Regulatory Commission, "Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy," FERC/PL99-3-000, September 15, 1999, p. 23. <https://www.ferc.gov/legal/maj-ord-reg/PL99-3-000.pdf>
- 13 Cross-Subsidization Restrictions on Affiliate Transactions, 122 FERC ¶ 61,155 at P 4 (2008) ("a franchised public utility and an affiliate may be able to transact in ways that transfer benefits from the captive customers of the franchised public utility to the affiliate and its shareholders"); Transcon. Gas Pipe Line Corp., 60 FERC ¶ 62,153 at p. 63, 378 (1992) ("Transactions between affiliates create special concerns due to the fact that these are not arms-length transactions").
- 14 Public Citizen Inc., "Petition To FERC To Initiate A Rulemaking To Establish The Office Of Public Participation As Established By Congress And To Fund Its Work," FERC Docket No. RM16-9, March 7, 2016. <https://www.citizen.org/sites/default/files/public-citizen-ferc-public-participation-petition.pdf>
- 15 On lax regulatory oversight see: Nadia Steinzor, "Blackout in the Gas Patch: How Pennsylvania Residents are Left in the Dark on Health and Enforcement," Earthworks, August 7, 2014. <https://www.earthworksonaction.org/library/detail/blackout-WZclaSiGOUk>
- 16 Rystad Energy AS, August 2017 Update.
- 17 Lorne Stockman, "A Bridge Too Far: How Appalachian Basin Gas Pipeline Expansion Will Undermine U.S. Climate Goals." Oil Change International, July 2016. <http://priceofoil.org/2016/07/22/a-bridge-too-far-report/>
- 18 Climate Action Tracker, "Foot Off the Gas: Increased Reliance on Natural Gas in the Power Sector Risks an Emissions Lock-In," Climate Analytics, New Climate Institute, Ecofys, June 2017. http://climateactiontracker.org/assets/publications/briefing_papers/CAT-2017-06-16-DecarbonisationSeries-NaturalGas.pdf
- 19 Matthew Hoza, "Appalachian Gas on Collision Course?," BTU Analytics, July 20, 2017. <https://btuanalytics.com/appalachian-gas-collision-course/>
- 20 Norman Bay, "Order Granting Abandonment and Issuing Certificates; BAY, Commissioner, Separate Statement," FERC Docket No. CP15-115-000, February 3, 2017, p. 1. <https://www.ferc.gov/CalendarFiles/20170203194955-CP15-115-000.pdf>
- 21 U.S. Energy Information Administration, "U.S. Natural Gas Total Consumption," <https://www.eia.gov/dnav/ng/hist/n9140us2a.htm>
- 22 Calculation based on FERC data on major approved and pending projects as of July 2017. This calculation includes pipelines that would add 100 or more miles of new takeaway capacity out of the Appalachian Basin specifically, and that were already approved in 2017 or could be approved in 2017. See FERC, "Approved Major Pipeline Projects (2009-Present)," <https://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp>; FERC "Major Pipeline Projects Pending (Onshore)," <https://www.ferc.gov/industries/gas/indus-act/pipelines/pending-projects.asp>.
- 23 Anastacia Dialynas, "U.S. Gas Insight: Pipelines to boost App Basin Takeaway. Forecasted build-out of App Basin Gas Pipelines, 2017-18," Bloomberg New Energy Finance, March 2, 2017. Available by subscription from www.BNEF.com
- 24 Based on U.S. Prime Rate: http://www.fedprimerate.com/wall_street_journal_prime_rate_history.htm
- 25 Natural Gas Act of 1938, Section 7 (15 USC §717f)
- 26 "Certificate of Public Convenience and Necessity for Interstate Natural Gas Pipelines," U.S. Government Permitting Dashboard. <https://www.permits.performance.gov/tools/certificate-public-convenience-and-necessity-interstate-natural-gas-pipelines>
- 27 See: Federal Energy Regulatory Commission, "Turtle Bayou Gas Storage Company, LLC, Docket No. CP10-481-000. Order Denying Application for Certificate Authorizations," June 6, 2011. <https://www.ferc.gov/whats-new/comm-meet/2011/061611/C-3.pdf>; Federal Energy Regulatory Commission, "Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP, Docket Nos CP13-483-000 and CP13-492-000. Order Denying Applications for Certificate and Section 3 Authorization," March 11, 2016. <https://www.ferc.gov/CalendarFiles/20160311154932-CP13-483-000.pdf>
- 28 Federal Energy Regulatory Commission, "Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy," FERC/PL99-3-000, September 15, 1999, p. 23. <https://www.ferc.gov/legal/maj-ord-reg/PL99-3-000.pdf>
- 29 Ibid., p. 16; 26.
- 30 Norman Bay, "Order Granting Abandonment and Issuing Certificates; BAY, Commissioner, Separate Statement," FERC Docket No. CP15-115-000, February 3, 2017, p. 3. <https://www.ferc.gov/CalendarFiles/20170203194955-CP15-115-000.pdf>
- 31 Rick Smead, "You Never Can Tell - With FERC Back In Business, What Does It Mean For Gas Projects?," RBN Energy Blog, August 21, 2017. <https://rbnenergy.com/you-never-can-tell-with-ferc-back-in-business-what-does-it-mean-for-gas-projects>
- 32 See Federal Energy Regulatory Commission, "Mountain Valley Project and Equitrans Expansion Project Final Environmental Impact Statement," FERC/FEIS-0272F, June 23, 2017, p. 1-8 <https://www.ferc.gov/industries/gas/enviro/eis/2017/06-23-17-FEIS/Final-Environmental-Impact-Statement.pdf>
- 33 See Federal Energy Regulatory Commission, "PennEast Pipeline Project Final Environmental Impact Statement, Volume I," FERC/FEIS: 0271F, April 7, 2017, p. 3-3. <https://www.ferc.gov/industries/gas/enviro/eis/2017/04-07-17-FEIS/Final-Environmental-Impact-Statement.pdf>
- 34 Federal Energy Regulatory Commission, "Atlantic Coast Pipeline and Supply Header Project Draft Environmental Impact Statement, Volume I," FERC/FEIS-0274D, December 30, 2016, p. 1-2. <https://www.ferc.gov/industries/gas/enviro/eis/2016/12-30-16-DEIS/volume-I.pdf>
- 35 Federal Energy Regulatory Commission, "Order Issuing Certificates and Granting Abandonment," FERC Docket Nos. CP16-22-000, CP16-23-000, CP16-24-000, CP16-102-000, August 25, 2017, p. 15. <https://www.ferc.gov/CalendarFiles/20170825170323-CP16-22-000.pdf>
- 36 Ibid., p. 19; pp. 13-14
- 37 Ibid., p. 12
- 38 "Q1 2017 DTE Energy Co Earnings Call - Final," Bloomberg Government Disclosure, April 26, 2017, p. 9 (Accessed via Factiva)
- 39 Federal Energy Regulatory Commission, "PennEast Pipeline Project Final Environmental Impact Statement, Volume I," FERC/FEIS: 0271F, April 7, 2017, p. 3-3. <https://www.ferc.gov/industries/gas/enviro/eis/2017/04-07-17-FEIS/Final-Environmental-Impact-Statement.pdf>
- 40 Federal Energy Regulatory Commission, "Mountain Valley Project and Equitrans Expansion Project Final Environmental Impact Statement," FERC/FEIS-0272F, June 23, 2017, p. 3-4. <https://www.ferc.gov/industries/gas/enviro/eis/2017/06-23-17-FEIS/Final-Environmental-Impact-Statement.pdf>
- 41 Norman Bay, "Order Granting Abandonment and Issuing Certificates; BAY, Commissioner, Separate Statement," FERC Docket No. CP15-115-000, February 3, 2017, p. 3. <https://www.ferc.gov/CalendarFiles/20170203194955-CP15-115-000.pdf>
- 42 See Tallgrass Interstate Gas Transmission, LLC, "Summary of the Prepared Direct Testimony of Alexander Kirk. Docket No. RP16-137; Exhibit No. TIG-34," Federal Energy Regulatory Commission, October 2015. <https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14033402>; and Great Lakes Gas Transmission, "Summary of the Prepared Direct Testimony of Alexander J. Kirk. Docket No. RP17-598; Exhibit No. GL-011," Federal Energy Regulatory Commission, March 2017. <https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14541555>
- 43 Ibid., p. 23 (Tallgrass) and p. 33 (Great Lakes)
- 44 Conditional Protest of the Missouri Public Service Commission, FERC Docket No. CP17-40-000, February 27, 2017. <http://priceofoil.org/content/uploads/2017/08/FERC-SPIRE-MoPSC-20170227-517832007267.pdf>
- 45 North Carolina Utilities Commission Protest of Proposed Recourse Rates, FERC Docket No. CP15-554, October 23, 2015. http://www.svnva.org/wp-content/uploads/North-Carolina-Utilities-Commission-to-FERC-10_23_2015.pdf
- 46 "Eminent Domain," Cornell Law School Legal Information Institute. https://www.law.cornell.edu/wex/eminent_domain
- 47 For the text of the amended act see: <http://legisworks.org/sal/61/stats/STATUTE-61-Pg459b.pdf>
- 48 "Landowners Sue FERC to Stop Eminent Domain for Mountain Valley and Atlantic Coast Pipelines," Bold Alliance, September 5, 2017. <http://boldalliance.org/ferc/>
- 49 Andrew Bradford, "Sabal Trail Adding Pipeline Capacity But Not Demand," BTU Analytics, June 20, 2017. <https://btuanalytics.com/sabal-trail-pipeline-capacity>
- 50 Ibid.
- 51 Ibid.
- 52 "Financial Concepts: The Risk/Return Tradeoff," Investopedia, <http://www.investopedia.com/university/concepts/conceptsl.asp>
- 53 Dr. Steve Isser, "Natural Gas Pipeline Certification and Ratemaking," October 19, 2016. http://rethinkenergy.org/wp-content/uploads/2016/10/ISSER_REPORT_CV.pdf
- 54 Ibid.
- 55 "Monthly Prime Rate History," FedPrimeRate.com, 2017, http://www.fedprimerate.com/wall_street_journal_prime_rate_history.htm
- 56 Ibid.
- 57 "Moody's upgrades Duke Energy and five subsidiaries; outlooks stable," Moody's Global Credit Research, January 31, 2014. https://www.moody.com/research/Moodys-upgrades-Duke-Energy-and-five-subsidiaries-outlooks-stable--PR_291348
- 58 Ass'n of Bus. Advocating Tariff Equity et. al. v. Midcontinent Indep. System Operator, Inc, et al., 156 FERC ¶ 61,234, United States of America Federal Energy Regulatory Commission, Docket No. EL14-12-002, September 28, 2016

- 59 Robert Walton, "Breaking down FERC's recent, and pending, ROE decisions," Utility Dive, November 17, 2014, <http://www.utilitydive.com/news/breaking-down-fercs-recent-and-pending-roe-decisions/334107/>.
- 60 Order Clarifying Statement of Policy, 90 FERC ¶ 61, 128 (2000); Certification of New Interstate Natural Gas Pipeline Facilities, Docket No. PL99-3-001, Issued February 9, 2000, p4 (emphasis added) <https://www.ferc.gov/legal/maj-ord-reg/PL99-3-001.pdf>
- 61 Dr. Steve Isser, op. cit.
- 62 Federal Energy Regulatory Commission, News Release: "FERC Proposes Reforms to Uplift Cost Allocation and Transparency," Docket No. RM17-2-000 Item No. E-1, January 19, 2017. <https://www.ferc.gov/media/news-releases/2017/2017-1/01-19-17-E-1.asp#WW4jx4yuUk>
- 63 Federal Energy Regulatory Commission, "Transmission Investment," March 29, 2017. <https://www.ferc.gov/industries/electric/indus-act/trans-invest.asp>
- 64 Atlantic Coast Pipeline, "Federal Energy Regulatory Commission Releases Favorable Environmental Report for the Atlantic Coast Pipeline," July 21, 2017. <https://atlanticcoastpipeline.com/news/2017/7/21/federal-energy-regulatory-commission-releases-favorable-environmental-report-for-the-atlantic-coast-pipeline.aspx>
- 65 Amendment to Application for a Certificate of Public Convenience and Necessity and Blanket Certificates, Atlantic Coast Pipeline, Docket No. CP15-554-001, Volume I Public, March 11, 2016, Exhibit P
- 66 Application for Certificate of Public Convenience and Necessity, Virginia Southside Expansion Project II, Filed March 23, 2015, Exhibit P
- 67 Terry Yen and Naser Ameen, "Natural gas pipeline projects lead to smaller price discounts in Appalachian region," U.S. Energy Information Administration. Today in Energy, August 16, 2017. <https://www.eia.gov/todayinenergy/detail.php?id=32512>
- 68 Federal Energy Regulatory Commission, "Mountain Valley Project and Equitrans Expansion Project Final Environmental Impact Statement," FERC/FEIS-0272F, June 23, 2017, p. 1-10. <https://www.ferc.gov/industries/gas/enviro/eis/2017/06-23-17-FEIS/Final-Environmental-Impact-Statement.pdf>
- 69 Appalachian Mountain Advocates, "2nd Revised Motion to Answer and Answer of Appalachian Mountain Advocates et al. under CP16-10," FERC Docket No. CP16-10, March 31, 2017. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14554557
- 70 Ibid.
- 71 Environmental Defense Fund, "Case No. 93-G-0932 - Heightened Scrutiny of Precedent Agreements Supported by Affiliates," New York State Public Service Commission Case No. 93-G-0932, June 19, 2017. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=34F4E228B-DD40-4F3A-8D36-EB908EEC505F>
- 72 New Jersey Division of Rate Counsel, "Comments of the New Jersey Division of Rate Counsel under CP15-558 (Draft Environmental Impact Statement for the PennEast Pipeline LLC)," Federal Energy Regulatory Commission, September 12, 2016, p. 4. https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20160912-6003. At the time the New Jersey Division of Rate Counsel filed these comments, PennEast affiliates accounted for approximately 610,000 Dekatherms per day (Dth/d) of the pipeline's 990,000 Dth/d of subscribed capacity. Since PSEG completed the sale of its ownership stake to Spectra/Enbridge on June 7, 2017, 485,000 Dth/d of 990,000 Dth/d of capacity, or just under 50 percent, remain under contract to affiliates.
- 73 Ibid.
- 74 Ibid. p. 8.
- 75 Ibid. p. 5-8
- 76 Ibid. p. 6
- 77 Ibid. p. 9-10
- 78 Ibid. p. 9
- 79 Federal Energy Regulatory Commission, "Final Environmental Impact Statement, Volume I, NEXUS Gas Transmission Project and Texas Eastern Appalachian Lease Project," FERC/FEIS-270F, November 30, 2016, p. 1-3-1-4. <https://www.ferc.gov/industries/gas/enviro/eis/2016/11-30-16-eis/FEIS.pdf>
- 80 Sam Levin, "Firm behind Dakota Access pipeline faces intense scrutiny for series of leaks," The Guardian, May 25, 2017. <https://www.theguardian.com/environment/2017/may/25/energy-transfer-partners-dakota-access-oil-leaks-ohio>
- 81 Gordon Jaremk, "BC endorses TransCanada's Mainline toll cut to revive natural gas sales," Natural Gas Intelligence Daily, June 23, 2017. <http://www.naturalgasintel.com/articles/110885-bc-endorses-transcanadas-mainline-toll-cut-to-revive-natural-gas-sales>
- 82 Federal Energy Regulatory Commission, "Order Issuing Certificates and Granting Abandonment," FERC Docket Nos. CP16-22-000, CP16-23-000, CP16-24-000, CP16-102-000, August 25, 2017. <https://www.ferc.gov/CalendarFiles/20170825170323-CP16-22-000.pdf>
- 83 Ibid., p. 12
- 84 "Q1 2017 DTE Energy Co Earnings Call - Final," Bloomberg Government Disclosure, April 26, 2017, p. 9 (Accessed via Factiva)
- 85 For DTE Electric precedent agreement summary, see Michigan Public Service Commission, "Michigan Public Service Commission Staff's Initial Brief," Case No. U-17920, p. 2. <https://efile.mpsc.state.mi.us/efile/docs/17920/0105.pdf>. For DTE Gas precedent agreement summary, see Michigan Public Service Commission, "Notice of Proposal for Decision," Case No. U-17691, p. 8-9. http://www.michigan.gov/documents/mpsc/u17691notpfd.70716_572486_7.pdf
- 86 Sierra Club, "Motion to Lodge of Sierra Club under CP16-22," FERC, April 4, 2017, p. 3-4. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14555755
- 87 See Michigan Public Service Commission, "Order," Case No. U-17691, November 22, 2016, p. 14-22. http://www.michigan.gov/documents/mpsc/u-17691_11-22-16_569183_7.pdf and Michigan Public Service Commission, "Order," Case No. U-17920, January 12, 2017, p. 3-4. http://www.michigan.gov/documents/mpsc/u-17920_1-12-17_565190_7.pdf
- 88 Michigan Public Service Commission, "Order," Case No. U-17691, November 22, 2016, p. 14-22. http://www.michigan.gov/documents/mpsc/u-17691_11-22-16_569183_7.pdf and Michigan Public Service Commission, "Order," Case No. U-17920, January 12, 2017, p. 3-4. http://www.michigan.gov/documents/mpsc/u-17920_1-12-17_565190_7.pdf
- 89 Bloomberg New Energy Finance and the Business Council for Sustainable Energy, "Sustainable Energy in America: 2017 Factbook. February 2017," Bloomberg Finance L.P., 2017, Executive Summary p. 3. <http://www.bcse.org/wp-content/uploads/2017-Sustainable-Energy-in-America-Factbook-Executive-Summary.pdf>
- 90 Tony Scott, "POWER DEMAND A ZERO SUM GAME?" BTU Analytics, September 22, 2014. <https://btuanalytics.com/power-demand-zero-sum-game/>
- 91 U.S. Energy Information Administration, "June 2017 Monthly Energy Review," June 28, 2017. <https://www.eia.gov/totalenergy/data/monthly/archive/00351706.pdf>
- 92 Ibid.
- 93 Bloomberg New Energy Finance and the Business Council for Sustainable Energy, "Sustainable Energy in America: 2017 Factbook. February 2017," Bloomberg Finance L.P., 2017, Executive Summary p. 3. <http://www.bcse.org/wp-content/uploads/2017-Sustainable-Energy-in-America-Factbook-Executive-Summary.pdf>
- 94 Based on 500MW coal plant at 64% utilization, see endnote 14 in, "The Greatest Energy Story You Haven't Heard," American Council for an Energy-Efficient Economy, October 2016. <http://aceee.org/sites/default/files/publications/researchreports/u1604.pdf>
- 95 Bloomberg New Energy Finance, New Energy Outlook 2017. Available by subscription from www.BNEF.com
- 96 Ibid.
- 97 Ibid.
- 98 Gavin Bade, "The Next Generation Utility Business Model: What you need to know." Utility Dive, May 10, 2017. <http://www.utilitydive.com/news/the-next-generation-utility-business-model-what-you-need-to-know/442421/>
- 99 U.S. Energy Information Administration, Jan. 2017. <https://www.eia.gov/outlooks/aec/data/browser/>
- 100 Steve Yetiv and Lowell Field, "Why Energy Forecasting Goes Wildly Wrong," Journal of Energy Security, October 23, 2017. http://ensec.org/index.php?option=com_content&view=article&id=466:why-energy-forecasting-goes-wildly-wrong&catid=139:issue-content&Itemid=425
- 101 Chelsea Harvey, "How we get energy is changing fast — and it's sparking a huge fight over forecasting the future," The Washington Post, May 13, 2016. https://www.washingtonpost.com/news/energy-environment/wp/2016/05/13/how-we-get-energy-is-changing-rapidly-and-its-sparking-a-huge-fight-over-forecasting-the-future/?utm_term=.10bf6f594e95
- 102 Sierra Club, "The Gas Rush," 2016. <http://content.sierraclub.org/naturalgas/gas-rush>
- 103 Ivy Main, "A Candidate's Guide to Clean Energy and the Pipelines," August 18, 2017, Power for the People VA. <https://powerforthepeopleva.com/2017/08/18/a-candidates-guide-to-clean-energy-and-the-pipelines/>
- 104 Jonathan Nelson, "Calif. capacity factors may indicate retirement risk," Platts Gas Daily, Volume 33, Issue 228, November 28, 2016.
- 105 Ibid.
- 106 U.S. Energy Information Administration, "Electricity Data Browser," Accessed Aug. 31, 2017. <https://www.eia.gov/electricity/data/browser/>
- 107 BNEF, NEO 2017, op. cit.
- 108 BTU Analytics, "Will Historical Assumptions Blindside the Power Burn Bulls?" April 5, 2016. <https://btuanalytics.com/will-historical-assumptions-blindside-the-power-burn-bulls/>; Tony Scott, "Electricity Demand Failing to Provide Spark for Gas," BTU Analytics, December 6, 2016. <https://btuanalytics.com/electricity-demand-natural-gas/>
- 109 Matthew Hoza, "Gas Under Pressure: Renewables take a toll," BTU Analytics, June 27, 2017. <https://btuanalytics.com/renewables-taking-toll-natural-gas/>
- 110 Andrew Bradford, "Sabal Trail Adding Pipeline Capacity but not Demand," BTU Analytics, June 20, 2017. <https://btuanalytics.com/sabal-trail-pipeline-capacity/>
- 111 Jack Farchy and Kelly Gilblom, "What if Big Oil's bet on gas is wrong?," Bloomberg, July 17, 2017. <https://www.bloomberg.com/news/articles/2017-07-17/big-oil-sees-salvation-in-gas-but-what-if-it-s-the-wrong-bet>
- 112 Sheetal Nasta, "Can't Stand Losing You: An update of the gas supply demand balance and storage," June 13, 2017. <https://rbnenergy.com/cant-stand-losing-demand-an-update-of-the-gas-supply-demand-balance-and-storage>
- 113 Sheetal Nasta, "In A Northeast Minute...Everything Can Change - Marcellus/Utica Takeaway Projects To The Gulf Coast," RBN Energy Blog, May 29, 2017. <https://rbnenergy.com/in-a-northeast-minute-everything-can-change-marcellus-utica-takeaway-projects-to-the-gulf>
- 114 Sheetal Nasta, "Can't Stand Losing You: An update of the gas supply demand balance and storage," RBN Energy Blog, June 13, 2017. <https://rbnenergy.com/cant-stand-losing-demand-an-update-of-the-gas-supply-demand-balance-and-storage>
- 115 U.S. Energy Information Administration, "Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets," October 2014. <https://www.eia.gov/analysis/requests/fe/pdf/eng.pdf>
- 116 Tyson Slocum, "Consumer & Small Business Benefits From Limiting Natural Gas & Oil Exports Testimony of Tyson Slocum, Energy Program Director, Public Citizen, before the U.S. Senate Committee on Small Business & Entrepreneurship," Public Citizen, July 14, 2015. https://www.sbc.senate.gov/public/_cache/files/c/8/c82daee23-415e-4338-9303-ee9af5e3b343/70393734F78E097C92107B9878CA9B42.slocum-testimony.pdf
- 117 Herman K. Trabish, "Gas plants or renewables? New LBNL study helps utilities compare the risks," Utility Dive, June 29, 2017. <http://www.utilitydive.com/news/gas-plants-or-renewables-new-lbnl-study-helps-utilities-compare-the-risks/441579/>
- 118 Ibid.
- 119 Mark Bollinger, "Using Probability of Exceedance to Compare the Resource Risk of Renewable and Gas-Fired Generation," Lawrence Berkeley National Laboratory, Report Number: LBNL-1007269, March 2017. <https://emp.lbl.gov/publications/using-probability-exceedance-compare/>
- 120 Bloomberg New Energy Finance and the Business Council for Sustainable Energy 2017, op. cit.
- 121 OECD/International Energy Agency (IEA), "Gas 2017: Analysis and Forecasts to 2022," July 2017. <http://www.oecd.org/publications/market-report-series-gas-2520274x.htm>
- 122 Cross-Subsidization Restrictions on Affiliate Transactions, 122 FERC ¶ 61,155 at P 4 (2008) ("a franchised public utility and an affiliate may be able to transact in ways that transfer benefits from the captive customers of the franchised public utility to the affiliate and its shareholders"); Transcon. Gas Pipe Line Corp., 60 FERC ¶ 62,153 at p. 63,378 (1992) ("Transactions between affiliates create special concerns due to the fact that these are not arms-length transactions.");
- 123 Public Citizen Inc., "Petition To FERC To Initiate A Rulemaking To Establish The Office Of Public Participation As Established By Congress And To Fund Its Work," FERC Docket No. RM16-9, March 7, 2016. <https://www.citizen.org/sites/default/files/public-citizen-ferc-public-participation-petition.pdf>



Oil Change International
714 G Street SE, Suite 202
Washington, DC 20003

www.priceofoil.org